GE Energy

Final Report:

New England Wind Integration Study

Prepared for:

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Foreword

This document was prepared by General Electric International, Inc. It is submitted to ISO New England, Inc. Technical and commercial questions and any correspondence concerning this document should be referred to:

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List of Acronyms and Abbreviations

ACE	Area Control Error
ATC	Available Transfer Capability
AWST	AWS Truepower
CC	Combined Cycle
CO2	Carbon Dioxide
CPS1	Control Performance Standard 1
CPS2	Control Performance Standard 2
CT	Combustion Turbine
CT-Oil	Oil Fueled Combustion Turbine
DAM	Day-Ahead Energy Market
EIA	Energy Information Agency
ELCC	Effective Load Carrying Capability
EWITS	Eastern Wind Integration and Transmission Study
FERC	Federal Energy Regulatory Commission
FLHR	Full Load Heat Rate
GT	Gas Turbine
CT-GAS	Gas Fueled Combustion Turbine
HVDC	High Voltage Direct Current
HQ IMP	Imports of energy from Hydro Quebec
ICR	Installed Capacity Requirement
IMP_EXP	Imports and Exports of Energy out of and into ISO-NE
IPR	Intermittent Power Resources
IVGTF	Integration of Variable Generation Task Force
LAI	Levitan and Associates
LMP	Locational Marginal Price
LOLE	Loss of Load Expectation
LTE	Long Time Emergency
MAE	Mean Absolute Error
MAPS	Multi Area Production Simulation

MARS	Multi Area Reliability Simulation
Net load	Time synchronous load minus wind generation output
NEWIS	New England Wind Integration Study
NEWRAM	New England Wind Resource Area Model
NLCD	National Land Cover Database
NOx	Nitrogen Oxides
NPCC	Northeast Power Coordinating Council
NREL	National Renewable Energy Laboratory
NUC	Nuclear Fission Fueled Steam Turbine
O&M	Operation and Maintenance
PAC	Planning Advisory Committee
PSH	Pumped Storage Hydro
RSP	Regional System Plan
RTM	Real-Time Energy Market
RTO	Regional Transmission Organization
SIS	System Impact Study
S-o-A	State of the Art
SOx	Sulfur Oxides
St-Coal	Coal Fueled Steam Turbine
St-Gas	Gas Fueled Steam Turbine
St-Oil	Oil Fueled Steam Turbine
St-Other	Cogeneration, Refuse, and Wood fueled generation
TKE	Turbulent Kinetic Energy
TMNSR	Ten Minute Non-Spinning Reserve
TMOR	Thirty Minute Operating Reserve
TMSR	Ten Minute Spinning Reserve
TOR	Total Operating Reserve
TRC	Technical Review Committee
USGS	United States Geological Survey
UWIG	Utility Wind Integration Group

Executive Summary

Introduction

Overview of ISO-NE

ISO New England Inc. (ISO-NE) is the not-for-profit corporation that serves as the Regional Transmission Organization (RTO) and Independent System Operator (ISO) for New England. ISO-NE is responsible for the reliable operation of New England's power generation, demand response, and transmission system; administers the region's wholesale electricity markets; and manages the comprehensive planning of the regional power system. ISO-NE has the responsibility to protect the short-term reliability and plan for the long-term reliability of the Balancing Authority Area, a six-state region that includes approximately 6.5 million businesses and households.

Key Drivers of Wind Power

The large-scale use of wind power is becoming a norm in many parts of the world. The increasing use of wind power is due to the emissions-free electrical energy it can generate; the speed with which wind power plants can be constructed; the generation fuel source diversity it adds to the resource mix; the long-term fuel-cost-certainty it possesses; and, in some instances, the cost-competitiveness of modern utility-scale wind power. Emissions-free generation helps meet environmental goals, such as Renewable Portfolio Standards (RPS)[1] and greenhouse gas control. Once the permitting process is complete, some wind power plants can be constructed in as little as three to six months, which facilitates financing and quick responses to market signals. Wind power, with a fuel cost fixed at essentially zero, can contribute to fuel-cost certainty, and would reduce New England's dependence on natural gas. In New England, the economics of wind power are directly affected by the outlook for the price of natural gas; higher fuel prices generally spur development of alternative energy supplies while lower fuel prices generally slow such development. Wind power development also is directly affected by environmental

[1] Each state in New England has adopted a renewable portfolio standard, except for Vermont, which has set renewable energy goals. RPSs set growing percentage-wise targets for electric energy supplied by retail suppliers to come from renewable energy sources. For a further description of New England related policies potentially affecting wind power see, for example, the ISO-NE Regional System Plan. RSP10 is available at: http://www.iso-ne.com/trans/rsp/index.html.

policy drivers such as restrictions on generator emissions or renewable energy generation targets.

While wind can provide low-priced zero-emissions energy, the variability of wind resources and the uncertainty with which the amount of power produced can be accurately forecasted poses challenges for the reliable operation and planning of the power system. Many favorable sites for wind development are remote from load centers. Development of these distant sites would likely require significant transmission development, which may not appear to be economical in comparison to conventional generation resources (at current prices) and could add complexity to the operations and planning of the system. The geographical diversity of wind power development throughout New England and its neighboring systems in New York and the eastern Canadian provinces would mitigate some of the adverse impacts of wind resource variability if the transmission infrastructure, operating procedures, and market signals were in place to absorb that variability across a larger system. Several Elective and Merchant Transmission Upgrades are in various stages of consideration to access these wind and other renewable resources.

Growth of Wind Power in New England

As of October 2010, approximately 270 megawatts (MW) of utility-scale wind generation are on line in the ISO New England system, of which approximately 240 MW are biddable assets. New England has approximately 3,200 MW of larger-scale wind projects in the ISO Generator Interconnection Queue, more than 1,000 MW of which represent offshore projects and more than 2,100 MW of which represent onshore projects.[2] The wind capacity numbers in the ISO queue are based on nameplate ratings. Figure 0–1 shows a map of planned and active wind projects in New England. As an upper bound of all potential wind resources—and not including the feasibility of siting potential wind projects—New England holds the theoretical potential for developing more than 215 gigawatts (GW) of onshore and offshore wind generation.[3]

[2] The 3,200 MW of wind in the queue is as of October 1, 2010, and includes projects in the affected non-FERC queue.

[3] 2009 Northeast Coordinated System Plan (May 24, 2010); http://iso-ne.com/committees/comm_wkgrps/othr/ipsac/ncsp/index.html.

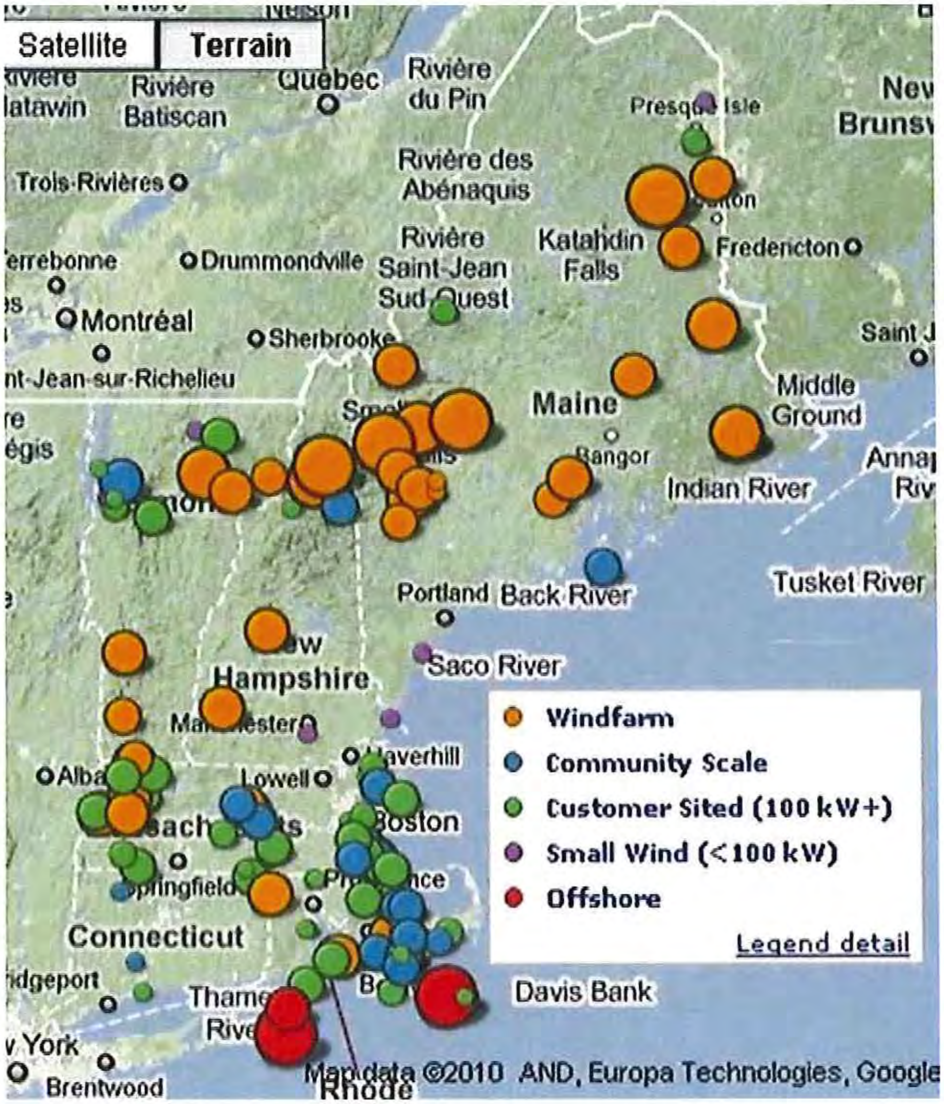

Figure 0–1 Planned and active wind projects in New England, 2010. Source: Sustainable Energy Advantage

The Governor's Economic Study

In 2009, the ISO completed the Scenario Analysis of Renewable Resource Development (the "Governors' Economic Study") – a comprehensive analysis for the integration of renewable resources over a long-term horizon, performed at the request of the Governors of the six New England states.[4] The Governors' Economic Study identified economic and environmental

[4] The Governor's Economic Study is available on the ISO's website at: http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/index.html.

impacts for a set of scenario analyses that assumed the development of renewable resources in New England. The study also identified the potential for significant wind power development in the New England states, the effective means to integrate this wind power development into the grid, and related preliminary transmission cost estimates. It did not evaluate operational impacts. Certain scenarios analyzed in the study indicated that, through development in the Northeast, New England and its neighbors could effectively meet the renewable energy goals of the region. Other scenarios showed that the region could be a net exporter of renewable energy.

The Governors' Economic Study ultimately informed the New England Governors' Renewable Energy Blueprint (the "Blueprint"), adopted last year by the six New England state governors.[5] The Blueprint sets forth policy objectives for the development of renewable resources in the Northeast that could ultimately lead to substantial penetration of wind power in New England.

Operational Effects of Large-scale Wind power

Large-scale wind integration adds complexity to power system operations by introducing a potentially large quantity of variable-output resources and the new challenge of forecasting wind power in addition to load.

The power system is designed and operated in a manner to accommodate a given level of uncertainty and variability that comes from the variability of load and the uncertainty associated with the load forecast as well as the uncertainty associated with the outage of different components of the system, such as generation or transmission. Due to a long familiarity with load patterns and the slowly changing nature of those patterns, the variability of the load is quite regular and well understood. The result is that the power system has been planned to ensure that different types of resources are available to respond to the variability of the load (e.g., baseload, intermediate, and fast-start resources have come into service) and the uncertainty associated with the load forecast is generally very small. The uncertainty associated with equipment outages is of a more discrete and "event" type nature that can be handled in a relatively deterministic fashion. This is the basis of contingency analysis where lists of credible contingencies are evaluated on a frequent periodic basis for their effects on power systems operations.

The Governor's Economic Study was conducted pursuant to the Regional System Planning Process established in Attachment K of the ISO OATT.

[5] See Blueprint Materials, available at: http://www.nescoe.com/Blueprint.html.

The combination of wind power's variability and the uncertainty of forecasting wind power make it fundamentally different from analyzing and operating other resources on the system. The weather patterns that drive the generation characteristics for wind power vary across many timescales and are loosely correlated with load. For example, ISO-NE experiences its peak loads during the summer months, while, as observed in this study, wind generation produces more energy during the winter months than in the summer. The uncertainty associated with wind generation is very different from the uncertainty associated with typical dispatchable resources. In general, uncertainty of energy supply from dispatchable conventional generation is due to forced unit outages due to equipment failures or other discrete events. Uncertainty in wind generation is more like uncertainty due to load. The amount of wind generation expected for the next day is forecasted in advance (just as load is forecasted in advance), and the amount of wind generation that actually occurs may be different from the forecasted amount, within the accuracy range of the forecast. In contrast, however, to forecasting of day-ahead load where typical average error is on the order of 1% to 3% Mean Absolute Error (MAE); the accuracy of state-of-the-art day-ahead wind forecasts is in the range of 15% to 20% MAE of installed wind rating. For small amounts of installed wind, load uncertainty dominates, but at higher penetrations of wind, forecast uncertainty becomes very important. In order to plan for the reliable operation of the power system, it is important to study how this combination of variability and associated uncertainty will affect power system operations far enough ahead of time for the effects to be quantified and any required mitigation measures to be put into service.

The loose correlation of wind and load requires the use of a new metric, "net load," to study the impact of large-scale wind generation where the fleet of dispatchable resources is used to balance the time-synchronous variability and uncertainty of the load minus the output of the wind generation. When managing the power system, the output of variable resources such as wind power can be directly subtracted from the amount of load to be served, the dispatchable resources on the system are then used to serve this remaining (i.e., "net") load in order to maintain the power system balance. The net load is then the true variability that must be managed with dispatchable resources and therefore it is the net load that must be studied when determining operational effects.

NEWIS Tasks and Analytical Approach

Anticipating the possible penetration of large-scale wind power in New England, ISO-NE also commissioned this comprehensive wind integration study in 2009 – the New England Wind

Integration Study (the NEWIS) – to assess the operational effects of large-scale wind penetration in New England using statistical and simulation analysis of historical data.[6,7] By focusing on the operational effects of large-scale wind integration, the NEWIS complements and builds on the results of the Governors' Economic Study.

The goals of the NEWIS were to determine the operational, planning and market impacts of integrating substantial wind generation resources for the New England Balancing Authority Area, with due consideration to the neighboring areas, as well as, the measures that may be available to ISO-NE for mitigating any negative impacts while enabling the integration of wind. The NEWIS also sets forth recommendations for implementing these measures. Additionally, the NEWIS identifies the potential operating conditions created or exacerbated by the variability and unpredictability of wind generation resources, and recommends potential corrective activities, recognizing the unique characteristics of the tightly integrated bulk power system in New England and the characteristic of wind generation resources. Consistent with the Governors' Economic Study, the NEWIS examines various scenarios of increasing wind power penetration up to approximately 12 GW of nameplate wind power.

In order to accomplish its goals, the NEWIS captures the unique characteristics of New England's bulk electrical system including load and ramping profiles, geography, system topology, supply and demand-side resource characteristics, and wind profiles and their unique impacts on system operations and planning with increasing wind power penetration. To facilitate the work of the NEWIS, it is broken into five tasks:

Wind Integration Study Survey - involved a review of the experience gained and lessons learned from several previous domestic and international wind integration studies on bulk electric power systems.

Technical Requirements for Interconnection - included the development of specific recommendations for technical requirements for wind generating resources; also investigated and recommended wind power forecasting tools that would be required for system operations as wind penetration increases. This task was completed in fall 2009, with recommendations to

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[6] See NEWIS Materials, New England Wind Integration Study (NEWIS) Wind Scenario and Transmission Overlays, available at: http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2010/jan212010/newis.pdf.

[7] The core project team included GE Energy Applications and Systems Engineering, EnerNex, and AWS Truepower. Many members of this team have extensive experience and have been among the pioneers of wind integration analysis.

ISO-NE detailed in a report titled "Technical Requirements for Wind Generation Interconnection and Integration"[8].

Mesoscale Wind Forecasting and Wind Plant Models - included development of an accurate and flexible mesoscale hindcasting model for the New England and Maritimes wind resource area (including offshore wind resources) that provides user-specified wind plant output profile data. This tool allows reuse of the mesoscale modeling data for further ISO-NE studies.

Scenario Development and Analysis - developed base case and wind generation scenarios, in consultation with ISO-NE and stakeholders, that included potential and probable scenarios for wind power development up to 24% annual wind energy penetration. This task also included statistical analysis to evaluate the impact of incremental wind generation on the operation of New England's bulk electric power system, focusing on the effects of variability and uncertainty.

Scenario Simulation and Analysis - included production simulations to evaluate the hourly operation of the various scenarios and penetration levels for three calendar years, as well as rigorous reliability calculations using Loss of Load Expectation (LOLE) methods to evaluate the capacity value of the wind generation.

In order to be clear about the interpretation of the methods used, results obtained, and any recommendations provided, it is important to recognize what the NEWIS is and what it is not. The NEWIS is neither a transmission planning study nor a blueprint for wind power development in New England, and large-scale wind power development might or might not occur in the region. The NEWIS takes a snapshot of a hypothetical future year where low, moderate, and large wind power penetrations are assumed. Feedback dynamics in markets, such as the impact of overall reduced fuel use and the changes in fuel use patterns on fuel supply and cost, were not analyzed or accounted for. It is not a goal of ISO-NE to increase the amount of any particular resource; instead the ISO's goal is to provide mechanisms to ensure that it can meet its responsibilities (stated above) for operating the system reliably, managing

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[8] See NEWIS Technical Report, available at:
http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2009/newis_report.pdf.
ISO-NE presented the recommendations of the NEWIS Technical Report to New England stakeholders at the November 18, 2009 meeting of the Planning Advisory Committee ("PAC"). *These recommendations will be subject to the applicable stakeholder processes prior to implementation.*

transparent and competitive power system markets, and planning for the future needs of the system, while providing a means to facilitate innovation and the fulfillment of New England's policy objectives. In this context, the NEWIS is meant to investigate whether there are any insurmountable operational challenges that would impede ISO-NE's ability to accept large amounts of wind generation.

A fundamental assumption in the NEWIS is that the transmission required to integrate the hypothesized wind generation into the bulk power system would be available and that the wind power resources would interconnect into those bulk transmission facilities. The NEWIS is a system-wide transportation study and, as such, does not account for local issues. For example, even with the limited wind generation that currently exists on the ISO-NE system, there are some instances where local transmission constraints result in curtailment of wind facilities due to the typical development pattern of wind generation facilities in New England and their interconnection under the minimum interconnection standards process. Implementing the recommendations developed as a result of the NEWIS will not solve these issues, unless the aforementioned sizable transmission expansions were to be built and the wind generation facilities were to connect directly into those expansions.

Another important assumption is that the available portfolio of non-wind generation in New England and neighboring systems was held constant across all alternatives considered. Neither attrition nor addition of new non-wind generation was considered as modifications to the base case.

Furthermore, detailed and extensive engineering analysis regarding stability and voltage limits would be required in order to determine the viability of the hypothesized transmission expansions, which in themselves may require substantial effort to site and build. It is also important to note that implementing the recommendations developed during the second task of the NEWIS (e.g., wind power specific grid support functions, wind power forecasting, windplant modeling, and communications and control) is essential for the reliable integration of large-scale wind power into the New England power system.

Finally, in addition to the significant observations mentioned above, changes may be required to systems and procedures within the ISO organization that are yet to be determined. These changes would require additional analysis for increasing levels of wind penetration and for issues identified within New England, or beyond, as system operators gain experience with wind energy. The development, implementation, and operating costs associated with these changes are not accounted for in this study.

Study Scenarios

All of the NEWIS wind scenarios are set to represent approximately the 2020 timeframe. In addition to the base case assumptions, there are five main categories of wind build-out scenarios representing successively greater penetrations of wind. The scenarios are categorized by the aggregate installed nameplate capacity of wind power and the simulated wind fleet's contribution to the region's forecasted annual energy demand. Values used for wind energy generated by each scenario are averages of the three years simulated via mesoscale modeling. Values of annual energy demand for the region and individual states are also averages for the three extrapolated load years used in the simulations and individual load supplied by energy efficiencies that has been bid into the Forward Capacity Market.

These categories of wind build-out scenarios include:

- Partial Queue Build-out
  - Represents 1.14 GW of installed wind capacity
  - Approximately 2.5% of the forecasted annual energy demand
- Full Queue Build-out
  - Represents 4.17 GW of installed wind capacity
  - Approximately 9% of the forecasted annual energy demand
- Medium wind penetration
  - Represents between 6.13 GW and 7.25 GW of installed wind capacity
  - Approximately 14% of the forecasted annual energy demand
- High wind penetration
  - Represents between 8.29 GW and 10.24 GW of installed wind capacity
  - Approximately 20% of the forecasted annual energy demand
- Extra-high wind penetration
  - Represents between 9.7 GW (for offshore) or 12 GW (for onshore) of installed wind capacity
  - Approximately 24% of the forecasted annual energy demand

Of the five categories, the Partial Queue and Full Queue build-outs are comprised of projects that were in the ISO Generator Interconnection Queue as of April 17, 2009, and the queue lists the proposed point of interconnection for each project. All of the build-outs with greater wind penetration consist of wind plants strategically chosen and added to the Full Queue site portfolio, until either the desired aggregate nameplate capacity or the desired energy contribution of the resulting wind fleet was satisfied. A range of wind plant scenarios was developed to represent what the New England system might look like with varying levels of wind penetration, and to represent different spatial patterns of wind development that could occur, including wind development in the Canadian Maritime Provinces. The objective of scenario development was to enable a detailed evaluation of the operational impacts of incremental wind generation variability and uncertainty on New England's bulk electric power system, including the incremental impact contributed by the spatial diversity of wind plants. The NEWIS was not intended to identify real or preferred wind integration scenarios.

In order to represent the impacts of wind portfolio diversity, five layout alternatives were developed for the medium and high wind penetration build-out scenarios, i.e., the 14% energy and 20% energy scenarios, based on sites with the best (highest) capacity factors. Two of these layout alternatives were also used for the extra-high wind penetration build-out scenario. A description of the five layout alternatives developed for each energy target follows:

1. Best Sites Onshore – This alternative includes the onshore sites with the highest capacity factor needed to satisfy the desired regional energy or installed capacity component provided by wind power. This alternative's wind fleet is comprised predominantly of wind plants in northern New England and therefore it exhibits low geographic diversity.

2. Best Sites Offshore – This alternative includes the offshore sites with the highest capacity factor needed to satisfy the desired regional energy or installed capacity component provided by wind power. This alternative features the highest overall capacity factor of each energy/capacity scenario set, but also a low geographic diversity. However, the steadier offshore wind resource features a higher correlation with load than onshore-based alternatives.

3. Balance Case – This alternative is a hybrid of the best onshore and offshore sites, and as such exhibits a high geographic diversity, including a good diversity by state. The offshore component of the wind fleet is divided equally between the states of Massachusetts, Rhode Island, and Maine (this is also the only alternative that includes offshore sites located in Maine).

4. Best Sites by State – This alternative likely represents the most spatially diverse native wind fleet, and is comprised of wind plants exhibiting the highest capacity factor within each state to meet that state's contribution of the desired energy goal. For example, in the 20% energy scenario, each state's wind fleet was built out in an attempt to meet 20% of the state's projected annual energy demand so that the

overall target of 20% of projected annual energy for New England was satisfied. This alternative enables the investigation of the effects of high diversity and wind power development close to New England's load centers. It should be noted that since the Full Queue contained a disproportionately high capacity of wind projects located in Maine, the aggregate energy produced from these plants contributes approximately 58% of this state's forecasted annual energy demand. This meant that the energy contribution of each of the other states was adjusted (percentage-wise) so that the regional wind fleet would produce the overall desired contribution to the forecasted regional energy demand.

5. Best Sites Maritimes – In addition to the Full Queue sites located within New England, this alternative is made up of extra-regional wind plants in the Canadian Maritime Provinces sufficient to satisfy the desired New England region's wind energy or installed capacity. No considerations were made regarding transmission upgrades required to deliver the hypothetical wind power to New England. Wind resources in the Maritimes exhibit a high geographic diversity and an overall capacity factor approaching that of New England's offshore resource. Considering the wind plants in the Full Queue, this alternative features the greatest geographic diversity. Also, given the longitudinal distance of the Maritimes from much of New England, the effects of integrating wind in the presence of time zone shifts could be highlighted.

Wind Data

AWS Truepower (AWST) developed a mesoscale wind model for the NEWIS study area, referred to as the New England Wind Resource Area Model (NEWRAM). The development of NEWRAM is based on the work that AWST conducted as part of the Eastern Wind Integration and Transmission Study (EWITS), for which AWST developed the wind resource and wind power output data. The resulting superset of simulated wind resource data is referred to as NREL's Eastern Wind Dataset and represents approximately 790 GW of potential future wind plant sites within the EWITS study area, and includes almost 39 GW of potential wind resource within the New England region. For the NEWIS, the New England portion of this wind dataset was expanded to include wind resources in the Canadian Maritimes and additional siting screens and validation analyses were applied. This NEWRAM dataset, which includes wind plant power output profiles as well as day-ahead wind forecasts for the calendar years of 2004, 2005, and 2006, provided the raw material necessary to build the various wind scenarios for the NEWIS.

Load Data

The load data used in the hourly production cost simulation analysis portion of the NEWIS comes from the ISO-NE pricing nodes (aka. p-nodes). P-nodes represent locations on the transmission system where generators inject power into the system or where loads withdraw power from the system. For the NEWIS, the load data from p-nodes has been aggregated into the respective Regional System Plan subareas. Historical data was extracted for years 2004, 2005, and 2006.

One-minute average total ISO New England load data was derived from the Plant Information (PI) data historian, which extracts data from the Energy Management System used for power system control.

Transmission Expansions

The NEWIS used a base-case transmission configuration for the 2019 ISO-NE system, as well as three transmission overlays developed as part of the previously described 2009 Governors' Study:

- 2019 ISO-NE System ("existing") – used for base case.[9]
- Governors' 2 GW Overlay – used as developed for Governor's Study.
- Governors' 4 GW Overlay/1,500 MW New Brunswick Interchange – An additional 345 kV line taken from the Governors' 8 GW Overlay was included for Southeastern Massachusetts in this overlay.
- Governors' 8 GW Overlay/1,500 MW New Brunswick Interchange

Due to scope constraints, only thermal limits were developed, investigated, and utilized for the NEWIS study. Voltage and stability limits would very likely reduce assumed transfer capability so the transfer capabilities of the hypothesized transmission expansion assumed in the study should be considered an upper bound.

Analytical Methods

The primary objective of this study was to identify and quantify system performance or operational problems with respect to load following, regulation, operating reserves, operation

[9] The base-case system for 2019 assumes completion of transmission projects in the 2009 RSP.

during low-load periods, etc. Three primary analytical methods were used to meet this objective: statistical analysis, hourly production simulation analysis, and reliability analysis. While the NEWIS tested the feasibility of wind integration under hypothetical future scenario analyses developed for the study, real world operating and system performance conditions can vary significantly from these types of hypothesized scenarios.

Statistical analysis was used to quantify variability due to system load, as well as wind generation over multiple time frames (annual, seasonal, daily, hourly, and 10-minute). The power grid already has significant variability due to periodic and random changes to system load. Wind generation adds to that variability, and increases what must be accommodated by load following and regulation with other generation resources. The statistical analysis quantified the grid variability due to load alone over several time scales, as well as the changes in grid variability due to wind generation for each scenario. The statistical analysis also characterized the forecast errors for wind generation.

Production simulation analysis with General Electric's Multi-Area Production Simulation software (GE MAPS) was used to evaluate hour-by-hour grid operation of each scenario for three years with different wind and load profiles. The production simulation results quantified numerous impacts on grid operation including the primary targets of investigation:

- Amount of maneuverable generation on-line during a given hour, including its available ramp-up and ramp-down capability to deal with grid variability due to load and wind
- Effects of day-ahead wind forecast alternatives in unit commitment
- Changes in dispatch of conventional generation resources due to the addition of new renewable generation
- Changes in transmission path loadings

Other measures of system performance were also quantified, including:

- Changes in emissions (NOx, SOx, CO2) due to renewable generation
- Changes in energy costs and revenues associated with grid operation, and changes in net cost of energy
- Changes in use and economic value of energy storage resources

Reliability analysis involved loss of load expectation (LOLE) calculations for ISO-NE system using General Electric's Multi-Area Reliability Simulation program (GE MARS). The analysis quantified the impact of wind generation on overall reliability measures, as well as the capacity values of the wind resources. ISO-NE's current method of determining the capacity value of wind plants was also compared with the LOLE/ELCC method. [10]

Impacts on system-level operating reserves were also analyzed using a variety of techniques including statistics and production simulation. This analysis quantified the effects of variability and uncertainty, and related that information to the system's increased need for operating reserves to maintain reliability and security.

The results from these analytical methods complemented each other, and provided a basis for developing observations, conclusions, and recommendations with respect to the successful integration of wind generation into the ISO-NE power grid.

Key Findings and Recommendations

The study results show that New England could potentially integrate wind resources to meet up to 24% of the region's total annual electric energy needs in 2020 if the system includes transmission upgrades comparable to the configurations identified in the Governors' Study. It is important to note that this study assumes (1) the continued availability of existing supply-side and demand-side resources as cleared through the second FCA (in other words, no significant retirements relative to the capacity cleared through the second FCA), (2) the retention of the additional resources cleared in the second Forward Capacity Auction, and (3) increases in regulation and operating reserves as recommended in this study.

Figure 0–2 shows the annual energy from the ISO-NE generation fleet with increasing levels of wind generation for the NEWIS study of the horizon year 2020. The pie charts are for the best sites onshore layout, but since energy targets are the same for all layout alternatives within each scenario, the results presented in the pie charts are very similar across the range of layout alternatives within each scenario.

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[10] Loss of load expectation (LOLE) is the expected number of hours or days that the load will not be met over a defined time period. Effective Load Carrying Capability (ELCC) is a data driven metric for capacity value, and represents the amount of additional load that can be served by the addition of a generator while maintaining the existing level of reliability.

The existing ISO-NE generation fleet is dominated by natural-gas-fired resources, which are potentially very flexible in terms of ramping and maneuvering. As shown in the upper left pie chart of Figure 0–2 natural gas resources provide about 50% of total annual electric energy in New England assuming no wind generation on the system. Wind generation would primarily displace natural-gas-fired generation since gas-fired generation is most often on the margin in the ISO-NE market. The pie charts show that as the penetration of wind generation increases, energy from natural gas resources is reduced while energy from other resources remains relatively constant. At a 24% wind energy penetration, natural gas resources would still be called upon to provide more than 25% of the total annual energy (lower right pie chart). In effect, a 24% wind energy scenario would likely result in wind and natural-gas-fired generation providing approximately the same amount of energy to the system, which would represent a major shift in the fuel mix for the region. It is unclear, given the large decrease in energy market revenues for natural-gas-fired resources, whether these units would be viable and therefore continue to be available to supply the system needs under this scenario.

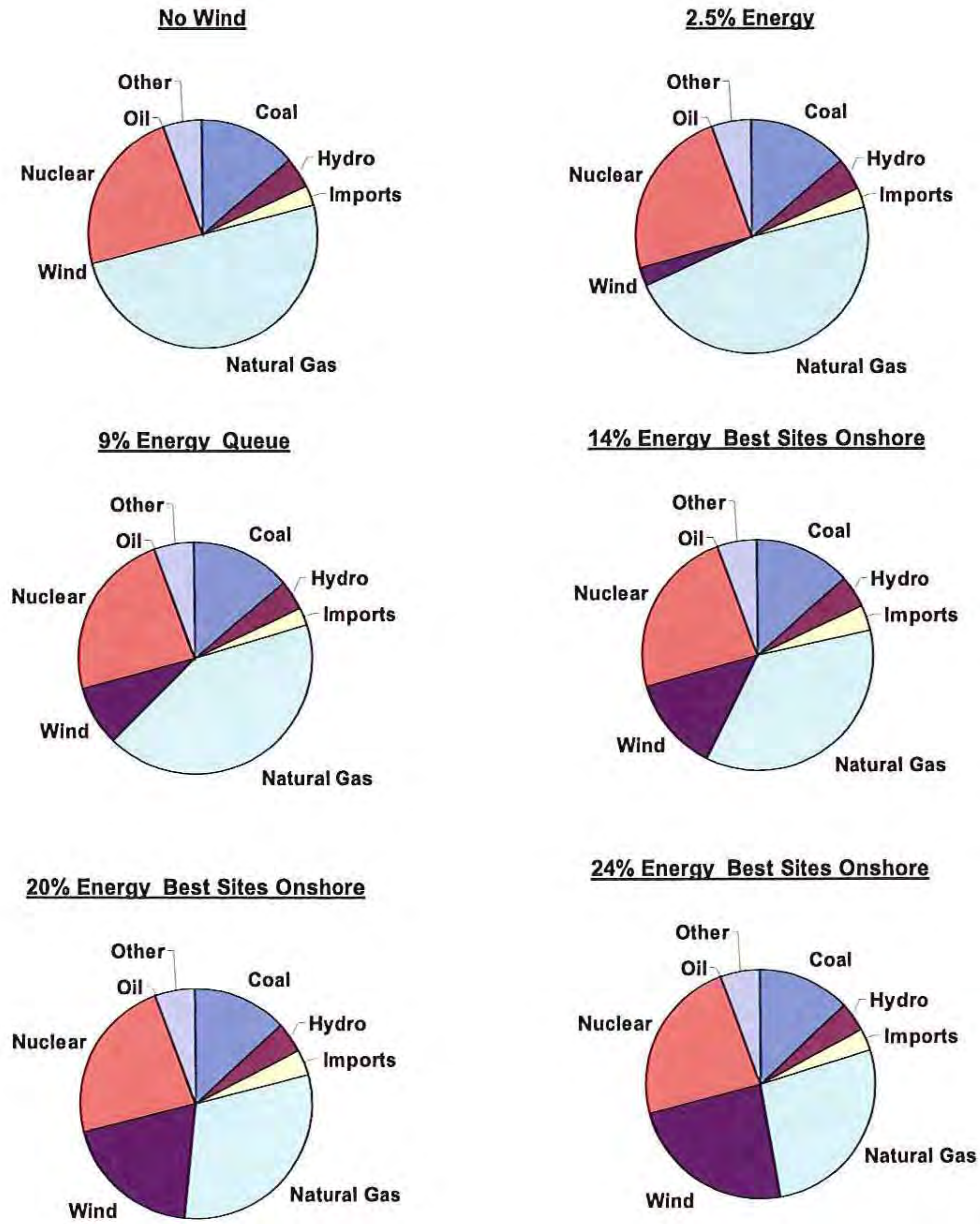

Figure 0–2 Annual Energy from ISO-NE Generation Fleet with Increasing Wind Energy Penetration.

The remainder of this chapter is organized as follows: The section on Statistical Analysis through the section covering Capacity Value of Wind Generation summarize key analytical results related to statistical characterization of the scenarios, regulation and operating reserves, impacts on hourly operations, and capacity value of wind generation. The High-Level Comparison of Scenario Layouts section presents a high-level comparison of the study scenarios. The Recommended Changes to ISO-NE Operating Rules and Practices section presents recommended changes to ISO-NE operating rules and practices related to the following issues:

- Capacity Value
- Regulation
- Reserves
- Wind Forecasting
- Maintaining System Flexibility
- Wind Generation and Dispatch
- Saving and Analyzing Operating Data

The Other Observations from Study Results section summarizes other significant observations from the study results, including:

- Flexible Generation
- Energy Storage
- Dynamic Scheduling
- Load and Wind Forecasting with Distributed Wind Generation

The Technical Requirements for Interconnection of Wind Generation section relates recommendations and observations in this report back to the technical requirements for interconnection of wind plants in the previously published Task 2 report. The Future Work section includes recommendations for future work.

Statistical Analysis

The observations and conclusions here are made on the basis of three years of synthesized meteorological and wind production data corresponding to calendar years 2004, 2005, and 2006. Historical load data for those same calendar years were scaled up to account for anticipated load growth through year 2020.

The wind generation scenarios defined for this study show that the winter season in New England is where the highest wind energy production can be expected. As is the case in many other parts of the United States, the higher load season of summer is the "off-season" for wind generation.

While New England may benefit from an increase in electric energy provided by wind generation primarily during the winter period, the region will still need to have adequate capacity to serve summer peak demand. Given current operating practices and market structures, the potential displacement of electric energy provided by existing resources raises some concern for maintaining adequate capacity (essential for resource adequacy) and a flexible generation fleet (essential to balance the variability of wind generation).

The capacity factors for all scenarios follow the same general trend. Seasonal capacity factors above 45% in winter are observed for several of the scenarios. In summer, capacity factors drop to less than 30%, except for those scenarios that contain a significant share of offshore wind resources.

Based on averages over the entire dataset, seasonal daily patterns in both winter and summer exhibit some diurnal (daily) behavior. Winter wind production shows two daily maxima, one in the early morning after sunrise, and the other in late afternoon to early evening. Summer patterns contain a drop during the nighttime hours prior to sunrise, then an increase in production through the morning hours. It is enticing to think that such patterns could assist operationally with morning load pickup and peak energy demand, but the patterns described here are averages of many days. The likelihood of any specific day ascribing to the long-term average pattern is small.

The net load average patterns by season reveal only subtle changes from the average load shape. No significant operational issues can be detected from these average patterns. At the extremes, the minimum hourly net load over the data set is influenced substantially. In one of the 20% energy scenario layouts, the minimum net load drops from just about 10 GW for load alone to just over 3 GW. Impacts of these low net load periods were assessed with the production simulation analysis.

The day-ahead wind power forecasts developed for each scenario show an overall forecast accuracy of 15% to 20% Mean Absolute Error (MAE). This is consistent with what is considered the state of the commercial art. These forecast errors represent the major source of uncertainty attributable to wind generation. The impacts of forecast errors on hourly operations were evaluated in the production simulation analysis.

Shorter-term wind power forecasts are also valuable for system operations. This study addressed the use of persistence forecasts over the hour-ahead and ten-minute-ahead time periods. A persistence forecast assumes that future generation output will be the same as current conditions. For slowly changing conditions, short-term persistence forecasts are currently about as accurate statistically as those that are skill-based, but this relationship breaks down as hour-to-hour wind variability increases. Operationally significant changes in wind generation over short periods of time, from minutes to hours (known as ramping events), highlight this issue. As a first estimate, operationally significant ramps are often considered to be a 20 percent change in power production within 60 minutes or less. However, the actual percent change that is operationally significant varies depending on the characteristics of the power grid and its resources. As the rate and magnitude of a ramp increases, persistence forecasts tend to become less and less accurate for the prediction of short-term wind generation.

While the persistence assumption works for a study like this one, in reality ISO-NE will need better ramp-forecasting tools as wind penetration increases. Such tools would give operators the means to prepare for volatile periods by allocating additional reserves or making other system adjustments. There has been recent progress in this area and better ramp forecasting tools are now being developed. For example, AWS Truepower recently deployed a system for the Electric Reliability Council of Texas (ERCOT) known as the ERCOT Large Ramp Alert System (ELRAS), which provides probabilistic and deterministic ramp event forecast information through a customized web-based interface. ELRAS uses a weather prediction model running in a rapid update cycle, ramp regime-based advanced statistical techniques, and meteorological feature tracking software to predict a range of possible wind ramp scenarios over the next nine hours. It is highly recommended that ISO-NE pursue the development of a similar system tailored to forecast the types of ramps that may impact New England.

Regulation and Operating Reserves

Statistical analysis of load and wind generation profiles as well as ISO-NE operating records of Area Control Error (ACE) performance were used to quantify the impact of increasing penetration of wind generation on regulation and operating reserve requirements.[11]

All differences between the scenarios stem from the different variability characteristics extracted from three years of mesoscale wind production data in the NEWRAM. The methodology and ISO-NE load are the same for each scenario, so wind variability is the only source of differences between scenarios.

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[11] ACE is a measurement of the instantaneous difference between the net actual and scheduled electric energy flows over the interchange between two regions. It is used to evaluate system control performance in real-time operating conditions. The ISO uses the ACE to dispatch resources that can provide regulation service to the electric grid.

Regulation

Significant penetration of wind generation will increase the regulation capacity requirement and will increase the frequency of utilization of these resources. The study identified a need for an increase in the regulation requirement even in the lowest wind penetration scenario (2.5% wind energy), and the requirement would have noticeable increases for higher penetration levels. For example, the average regulation requirement for the load only (i.e., no wind) case was 82 MW. This requirement increases to 161 MW in the 9% wind energy scenario—and to as high as 313 MW in the 20% scenario.

The primary driver for increased regulation requirements due to wind power is the error in short-term wind power forecasting. The economic dispatch process is not equipped to adjust fast enough for the errors inherent in short-term wind forecasting and this error must be balanced by regulating resources. (This error must be accounted for in addition to the load forecasting error.)

Figure 0–3 shows regulation-duration curves for increasing levels of wind penetration. It shows the number of hours per year where regulation needs to be equal to or greater than a given value. For example, the dark blue curve (the left-most curve) shows that between 30 MW and 190 MW of regulation are required for load alone. The 2.5% Partial Queue scenario (the light blue line to the right of the load-only curve) increases the regulation requirement to a range of approximately 40 MW to 210 MW; the overall shape tracks that of the load-only regulation requirement curve. In the higher wind penetration scenarios, this minimum amount of required regulation capacity increases and the average amount of regulation required increases such that the shapes of the curves no longer track that of the load-only curve—this is indicative that the increased regulation capacity will likely be required to be utilized more frequently. The purple curve (the middle curve) shows that a range of approximately 50 MW to 270 MW of regulation is required with 9% wind energy penetration. The yellow and red curves (to the right of the 9% wind penetration curve just discussed) show that the required regulation increases to ranges of approximately 75 MW to 345 MW and approximately 80 MW to 430 MW, respectively. These estimates are based on rigorous statistical analysis of wind and load variability.

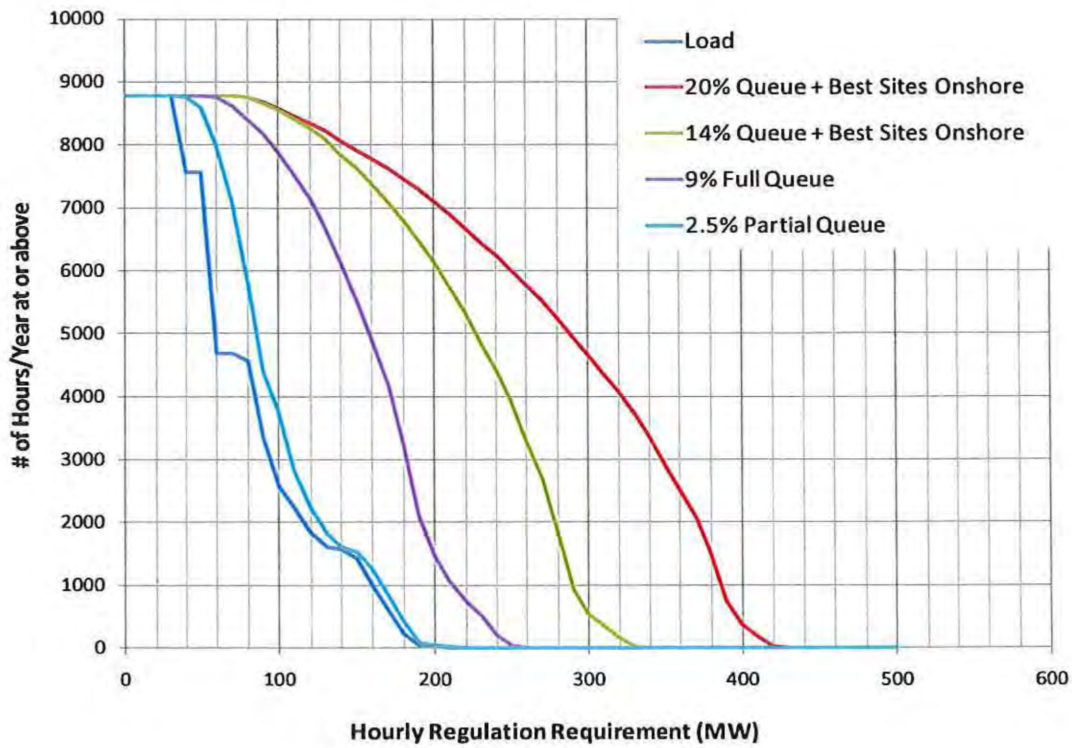

Figure 0–3 Regulation Requirements with Increasing Wind Energy Penetration

At 20% wind energy penetration, the average regulation requirement is estimated to increase from approximately 80 MW without wind, to a high of approximately 315 MW with 20% wind depending on the differences within the scenario. At lower penetration levels, the incremental regulation requirement is smaller. The hourly analysis indicates average regulation requirements would increase to a high of approximately 230 MW with 14% wind energy penetration. At 9% wind energy penetration, the average regulation would increase to approximately 160 MW. At the lowest wind penetration studied (2.5%) average required regulation capability would increase to approximately 100 MW. Alternate calculation methods that include historical records of ACE performance, synthesized 1-minute wind power output, and ISO-NE operating experience suggest that the regulation requirement may increase less than these amounts.

There are some small differences in regulation impacts discernable amongst layouts at the same energy penetration levels. This can be traced directly to the statistics of variability used in these calculations. Based on the ISO-NE wind generation mesoscale data, some scenario layouts of wind generation exhibit higher variability from one ten-minute interval to the next. A number of factors could contribute to this result, including the relative size of the individual plants in the scenario layout (and the impact on spatial and geographic diversity), the local characteristics of the wind resource as replicated in the numerical weather simulations from which the data is generated, and even the number of individual turbines comprising the scenario, as more turbines would imply more spatial diversity. At the same time, however, the differences may be within the margin of uncertainty inherent in the analytical methodologies for calculating regulation impacts. Given these uncertainties, it is difficult to draw concrete conclusions regarding the relative merits of one scenario layout over the others.

ISO-NE routinely analyzes regulation requirements and makes adjustments. As wind generation is developed in the market footprint, similar analyses will take place. Control performance objectives and the empirically observed operating data that includes wind generation should be taken into account in the regulation adjustment process.

ISO-NE's current practice for monitoring control performance and evaluating reserve policy should be expanded to explicitly include consideration of wind generation once it reaches a threshold where it is visible in operational metrics. A few methods by which this might be done are discussed in Chapter 4, and ISO-NE will likely find other and better ways as their experience with wind generation grows. ISO-NE should collect and archive high-resolution data from each wind generation facility to support these evaluations.

Analysis of these results indicates, assuming no attrition of resources capable of providing regulation capacity, that there may be adequate supply to match the increased regulation requirements under the wind integration scenarios considered. ISO-NE's business process is robust and is designed to assure regulation adequacy as the required amount of regulation develops over time and the needs of the system change.

Operating Reserves

Additional spinning and non-spinning reserves will be required as wind penetration grows. The analysis indicates that Ten Minute Spinning Reserve (TMSR) would need to be supplemented as penetration grows to maintain current levels of contingency response. Increasing TMSR by the average amount of additional regulation required for wind generation is a potential option to ensure that the spinning reserve available for contingencies would be consistent with current practice.

Using this approach, TMSR would likely need to increase by 310 MW for the 20% energy penetration scenarios, about 125 MW for 14% penetration, and about 80 MW for 9% penetration.

In addition to the penetration level, the amount is also dependent on the following factors:

- The amount of upward movement that can be extracted from the sub-hourly energy market – the analysis indicates that additional Ten Minutes Non-Spinning Reserve

(TMNSR), or a separate market product for wind generation, would be needed at 20% penetration

- The current production level of wind generation relative to the aggregate nameplate capacity, and
- The number of times per period (e.g., year) that TMSR and Thirty Minute Operating Reserve (TMOR) can be deployed – for the examples here, it was assumed that these would be deployed 10 times per period.

The amount of additional non-spinning reserve that would be needed under conditions of limited market flexibility and volatile wind generation conditions is about 300 MW for the 20% Best Sites Onshore case, and 150 MW for the 9% Energy Queue case. This incremental amount would maintain the TMNSR designated for contingency events per existing practice, where it is occasionally deployed for load changes. "Volatile wind generation conditions" would ultimately be based on ongoing monitoring and characterization of the operating wind generation. Over time, curves like those in Figure 4-5 would be developed from monitoring data and provide operators with an increasingly confident estimate of the expected amount of wind generation that could be lost over a defined interval.

The additional TMNSR would be used to cover potentially unforecasted extreme changes (reductions) in wind generation. As such, its purpose and frequency of deployment are different from the current TMNSR. This may require consideration of a separate market product that recognizes these differences. ISO-NE should also investigate whether additional TMOR could be substituted to some extent for the TMSR and/or TMNSR requirements related to wind variability.

Due to the increases in TMSR and TMNSR, overall Total Operating Reserve (TOR) increases in all wind energy scenarios. For the 2.5% wind energy scenario, the average required TOR increases from 2,250 MW to 2,270 MW as compared to the no wind energy scenario baseline. The average required TOR increases to approximately 2,600 MW with 14% wind penetration and about 2,750 MW with 20% penetration.

The need for additional reserves varies as a function of wind generation. Therefore, it would be advantageous to have a process for scheduling reserves day-ahead or several hours ahead, based on forecasted hourly wind generation. It may be inefficient to schedule additional reserves using the existing "schedule" approach, by hour of day and season of year, since that may result in carrying excessive reserves for most hours of the year. The process for developing and implementing a day-ahead reserves scheduling process may involve considerable effort and investigation of this process was outside the scope of the NEWIS.

Analysis of Hourly Operations

Production simulation analysis was used at an hourly time-step to investigate operations of the ISO-NE system for all the study scenarios under the previously stated assumptions of transmission expansion, no attrition of dispatchable resources, addition of resources that have cleared in the second Forward Capacity Auction, and the use of all of the technical capability of the system (i.e., exploiting all system flexibility). The results of this analysis indicate that integrating wind generation up to the 24% wind energy scenario is operationally feasible and may reduce average system-wide variable operating costs (i.e., fuel and variable O&M costs) in ISO-NE by $50 to $54 per megawatt-hour of wind energy[12]; however, these results are based on numerous assumptions and hypothetical scenarios developed for modeling purposes only. The reduction in system-wide variable operating cost is essentially the marginal cost of energy, which should not be equated to a reduction in $/MWh for market clearing price (i.e. Locational Marginal Prices--LMPs). Low-priced wind resources could displace marginal resources, but that differential is not the same as reductions in LMPs.

As mentioned briefly in the introduction to the hourly analysis, the cost information is included only as a byproduct of the production cost analysis and that the study was not intended primarily to compare cost impacts for the various scenarios. These results are not intended to predict outcomes of the future electric system or market conditions and therefore should not be considered the primary basis for evaluating the different scenarios.

Wind energy penetrations of 2.5%, 9%, 14%, 20%, and 24% were evaluated. As wind penetrations were increased up to 24%, there were increasing amounts of ramp down insufficiencies with up to approximately 540 hours where there may potentially be insufficient regulation down capability. There were no violations that occurred for the regulation up. The transmission system with the 4 GW overlay was adequately designed to handle 20% wind energy without significant congestion. The transmission system with the 8 GW overlay was adequately designed to handle 24% wind energy without significant congestion.

Wind generation primarily displaces natural-gas-fired combined cycle generation for all levels of wind penetration, with some coal displacement occurring at higher wind penetrations.

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[12] In essence, this is the cost to replace one MWh of energy from wind generation with one MWh of energy from the next available resource from the assumed fleet of conventional resources.

The study showed relatively small increases in use of existing pumped-storage hydro (PSH) for large wind penetrations; because balancing of net load—an essential requirement for large-scale wind integration—was largely provided by the flexibility of the natural-gas-fired generation fleet. It is possible that retirements (attrition) of some generation in the fleet would increase the utilization of PSH, but that was not examined in this study.

The lack of a price signal to increase use of energy storage is the primary reason the study showed small increases in the use of pumped-storage hydro in the higher wind penetrations. For energy arbitrage applications, like pumped storage hydro, a persistent spread in peak and off-peak prices is the most critical economic driver. The differences between on-peak and off-peak prices were small because natural-gas-fired generation remained on the margin most hours of the year. Over the past six years, GE has completed wind integration studies in Texas, California, Ontario, the western region of the United States, and Hawaii. In many of these studies, as the wind power penetration increases, spot prices tend to decrease, particularly during high priced peak hours. The off-peak hours remain relatively the same. Therefore, the peak and off-peak price spread shrinks and no longer has sufficient range for economic storage operation. An example of this can be seen in Figure 0–4. The figure shows the Locational Marginal Price (LMP) for the week of April 1, 2020, for the 20% Best Sites Onshore scenario, using year 2004 wind and load shapes. It also shows the LMP for a case with no wind generation. The price spread decreases substantially, which reduces the economic driver for energy storage due to price arbitrage.

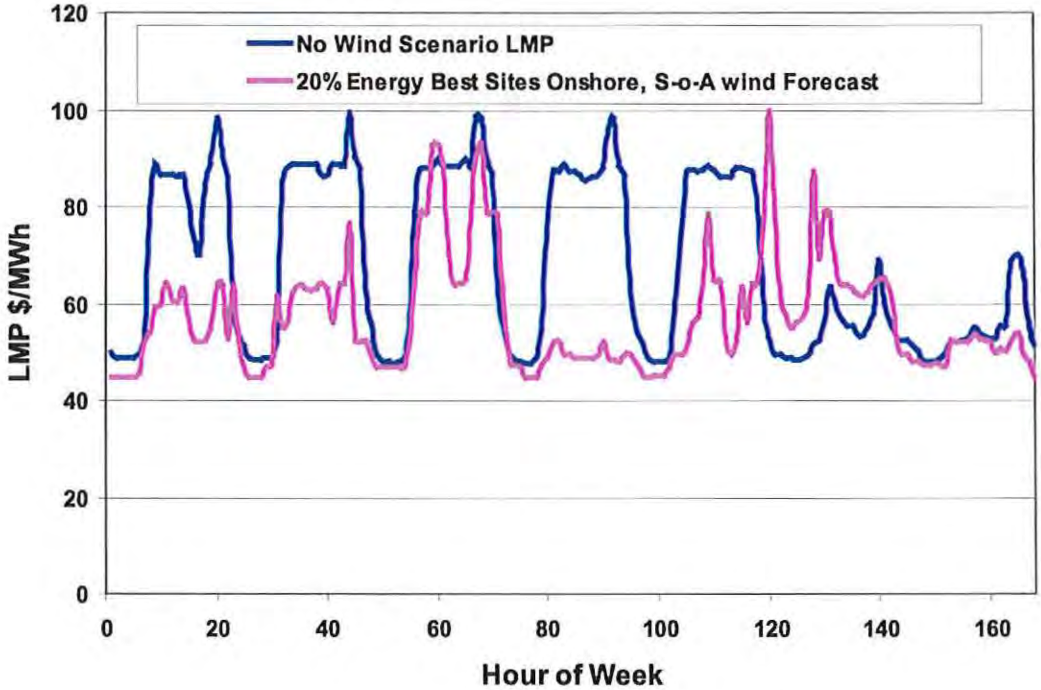

Figure 0–4 **LMP for Week of April 1, Comparison of No Wind and 20% Wind Energy**

With 20% wind energy penetration, the following impacts were observed on emissions and energy costs:

- NOx emissions were reduced by approximately 6,000 tons per year, a 26% reduction compared to no wind.
- SOx emissions were reduced by approximately 4,000 tons per year, a 6% reduction compared to no wind.
- CO_2 emissions were reduced by approximately 12,000,000 tons per year, a 25% reduction compared to no wind. (Wind generation will not displace other non- CO_2-producing generation, such as hydro and nuclear. Therefore, 20% energy from wind reduces the energy from CO_2-producing generation by 25 to 30%. Considering that wind generation primarily displaces natural-gas-fired generation in New England, the overall CO_2 production declines by 25% with 20% wind energy penetration).

- Average annual Locational Marginal Price (LMP) across ISO-NE[13] was reduced by
  - Best Sites Maritimes - $5/MWh
  - Best Sites Onshore - $6/MWh
  - Best Sites - $9/MWh
  - Best Sites Offshore - $9/MWh
  - Best Sites By State - $11/MWh

Variation in the LMP impact for the different layout alternatives results from the differences in the monthly wind profile as well as the daily profile. For example, the Maritimes layout alternative has slightly less energy in the summer than the other scenarios. Also, the Maritimes has less energy in the afternoon to early evening period, than the other scenarios when looking at the daily average summer profile. As mentioned briefly in the introduction to the hourly analysis, the cost information is included only as a byproduct of the production cost analysis and that the study was not intended primarily to compare cost impacts for the various scenarios. These results are not intended to predict outcomes of the future electric system or market conditions and actual changes in fuel prices, transmission system topology, and resource flexibility will have significant impacts on these results.

Revenue reductions for units not being displaced by wind energy is roughly 5%-10%, based on lower spot prices. For units that are being displaced, their revenue losses are even greater. This will likely lead to higher bids for capacity and may lead to higher bids for energy in order to maintain viability. The correct market signals must be in place in order to ensure that an adequate fleet of flexible resources is maintained.

The study scenarios utilized the transmission system overlays originally developed for the Governors' Study. With these transmission overlays, some scenarios exhibited no transmission congestion and others showed only a few hours per year with transmission congestion. This suggests that somewhat less extensive transmission enhancements might be adequate for the wind penetration levels studied, although further detailed transmission planning studies would be required to fully assess the transmission requirements of any actual wind generation projects.

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[13] Based on the hourly marginal unit price. The results also do not account for other factors that may change business models of market participants.

Capacity Value of Wind Generation

Table 0–1 summarizes the average three-year capacity values for the total New England wind generation for all the scenarios analyzed in this study as calculated using the Loss of Load Expectation (LOLE) methodology where wind generation is treated as a load modifier. As mentioned in the NEWIS Task 2 report, three years of data only give some indication as to the variability of the effective capacity of wind generation from year to year. Along with the effective capacity of each scenario, Table 0–1 also includes in brackets the percent of the installed capacity that is offshore for that scenario.

Wind capacity values can vary significantly with wind profiles, load profiles, and siting of the wind generation. For example, the 20% Best Sites Onshore scenario has a wind generation capacity value of 20% while the corresponding 20% Best Sites Offshore scenario has a 32% capacity value. The capacity value of wind generation is dominated by the wind performance during just a few hours of the year when load demand is high. Hence, the capacity value of wind generation can vary significantly from year to year. For example, the 20% Best Sites Offshore scenario had wind capacity values of 27%, 26% and 42% for 2004, 2005 and 2006 wind and load profiles, resulting in the 32% average capacity value shown in Table 0–1.

Table 0–1 Summary of Wind Generation Capacity Values by Scenario and Energy Penetration

Scenario	3-Year Average Capacity Value (%) [% Offshore]	14% Energy 3-Year Average Capacity Value (%) [% Offshore]	20% Energy 3-Year Average Capacity Value (%) [% Offshore]
2.5 % Energy	36% [40%]		
9% Energy (Queue)	28% [20%]		
Onshore		23% [12%]	20% [8%]
Maritimes		26% [13%]	26% [9%]
Best by States		28% [15%]	26% [29%]
Best Sites		35% [47%]	34% [51%]
Offshore		34% [45%]	32% [58%]

High-Level Comparison of Scenario Layouts

For a given penetration of wind energy, differences in the locations of wind plants had very little effect on overall system performance. For example, the system operating costs and operational performance were roughly the same for all the 20% wind energy penetration scenarios analyzed. This is primarily because all the wind layout alternatives had somewhat similar wind profiles (since all of the higher penetration scenarios included the wind generation from the Full Queue), there was no significant congestion on the assumed transmission systems, and the assumed system had considerable flexibility, which made it robust in its capability of managing the uncertainty and variability of additional wind generation across and between the studied scenarios.

The individual metrics (e.g., prices, emissions) are useful in comparing scenarios, but should not be used in isolation to identify a preferred scenario or to predict actual future results.

Offshore wind resources yielded higher capacity factors than onshore resources across all scenarios and also tended to better correlate with the system's electric load. The study indicates that offshore wind resources would have higher capital costs, but generally require less transmission expansion to access the electric grid. Some scenarios with the lowest predicted capital costs (for wind generation only) also required the most amount of transmission because the resources are remote from load centers and the existing transmission system.

Some scenarios that showed the least transmission congestion also required the greatest investment in transmission, so congestion results should not be evaluated apart from transmission expansion requirements. Some scenarios that showed the greatest reductions in LMPs and generator emissions also used wind resources with low capacity factors, which would result in higher capital costs. The complete results are described in the full report.

Recommended Changes to ISO-NE Operating Rules and Practices

Capacity Value: Capacity value of wind generation is a function of many factors, including wind generation profiles for specific wind plants, system load profiles, and the penetration level of wind generation on the ISO-NE system. ISO-NE currently estimates the capacity value using an approximate methodology based on the plant capacity factor during peak load hours. This methodology was examined in Chapter 6 and gives an overall reasonable approximation across the scenarios studied. Given that only three years of data were available for the LOLE calculation and that the results of this method can vary somewhat from year to year, it is recommended that ISO-NE monitor a comparison between its current approximate method and the LOLE/ELCC as operational experience is gained. As wind penetration increases, the Installed Capacity Requirement (ICR) may not accurately account for the intermittent nature of wind resources. GE recommends that the ISO evaluate potential improvements to the calculation of capacity values for wind resources. Given that the capacity value of wind is significantly less than that of typical dispatchable resources, much of the conventional capacity may be required regardless of wind penetration (Section 6.5).

Regulation: ISO-NE presently schedules regulation by time of day and season of year. This has historically worked well as regulation requirements were primarily driven by load, which has predictable diurnal and seasonal patterns. Wind generation does not have such regular patterns. At low levels of wind penetration, the existing process for scheduling regulation should be adequate, since the regulation requirement is not significantly affected by wind. However, with higher penetrations of wind generation (above 9%), it will likely become advantageous to adjust regulation requirements daily, as a function of forecasted and/or actual wind generation on the ISO-NE system. Due to the additional complexity of accommodating large-scale wind power, it is recommended that ISO-NE develop a methodology for calculating the regulation requirements for each hour of the next day, using day-ahead wind generation forecasts.

Determination of actual regulation requirements will need to grow from operating experience, similar to the present methods employed at ISO-NE. (See Section 4.4.3)

TMSR: Spinning reserve is presently dictated by largest contingency (typically 50% of 1,500 MW, the largest credible contingency on the system). ISO-NE presently includes regulation within TMSR. With increased wind penetration, regulation requirements will increase to a level where this practice may need to be changed – probably before the system reaches 9% wind energy penetration. Either regulation should be allocated separately from TMSR, or TMSR should be increased to cover the increased regulation requirements. The latter alternative was assumed for this study, and TMSR values in this report reflect that. (See Section 4.5.1)

TMNSR: Analysis of the production simulations for selected scenarios revealed that additional TMNSR might be needed to respond to large changes in wind generation over periods of tens of minutes to an hour or more. Given the assumption of no attrition of resources, displacement of marginal generation by wind energy may help to ensure that this capacity is available. In other words, some resources that are displaced by wind may be able to participate as fast start TMNSR—if those resources are assumed to continue to be available. A mechanism for securing this capacity as additional TMNSR during periods of volatile wind generation (as shown in the statistical analysis and the characterizations developed for the operating reserve analysis) may need to be developed. The use of TMOR instead of and/or in combination with TMNSR should be investigated (See Section 4.5.3).

Wind Forecast: Day-ahead wind forecasting should be included in the ISO-NE economic day-ahead security constrained unit commitment and reserve adequacy analysis. At the present level of wind penetration, this practice is not critical. At larger penetrations, if wind forecasts are not included in the economic day-ahead unit commitment, then conventional generation may be overcommitted, operating costs may be increased, LMPs may be depressed, the system may have much more spinning reserve margin than is necessary, and wind generation may be curtailed more often than necessary. Analysis performed for the NEWIS indicates that these effects, and hence the case for implementation of a wind power forecast, grows as wind power penetrations increase. Intra-day wind forecasting should also be performed in order to reduce dispatch inefficiencies and provide for situational awareness.

It would also be beneficial for ISO-NE to publish the day-ahead wind forecast along with the day-ahead load forecast, as this would contribute to overall market efficiency. Current practices for publishing the load forecast should be followed for publishing the wind forecast, subject to confidentiality requirements. This allows generation market participants to see the net load forecast and bid accordingly, just as they do with load today (See Section 5.2.4).

Wind Generation and Dispatch: Production simulation results showed increased hours of minimum generation conditions as wind penetration increases, which, given the policy support schemes for wind generation, implies increased frequency of negative LMPs. ISO-NE should not allow wind plants to respond in an uncontrolled manner to negative LMPs (e.g., as self-scheduled resources). Doing so may cause fast and excessive self-curtailment of wind generation. That is, due to their rapid control capability, all affected wind plants could possibly reduce their outputs to zero within a few minutes of receiving an unfavorable price signal. ISO-NE should consider adopting a methodology that sends dispatch signals to wind plants to control their output in a more granular and controlled manner (e.g., with dispatch down commands or specific curtailment orders). This method is recommended in the Task 2 report. NYISO has already implemented a similar method (See Section 5.2.1 for a discussion on the frequency of minimum generation issues).

System Flexibility: Increased wind generation will displace other supply-side resources and reduce flexibility of the dispatchable generation mix—in a manner that is system specific. Any conditions that reduce the system flexibility will potentially, negatively impact the ability of New England to integrate large amounts of wind power. Factors that could potentially reduce system flexibility can be market, regulatory, or operational practices, or system conditions that limit the ability of the system to use the flexibility of the available resources and can include such issues as: strict focus on (and possibly increased regulation of) marginal emissions rates as compared to total overall emissions, decreased external transaction frequency and/or capability, practices that impede the ability of all resources to provide all types of power system products within each resource's technical limits, and/or long-term outages of power system equipment or chronic transmission system congestion.

Strict focus on marginal emissions rates can reduce system flexibility by encouraging generators to operate in a manner that reduces their flexibility (e.g., reducing allowed ramp rates or raising minimum generation levels in order to limit marginal emissions rates) and ignores the fact that as non-emitting resources are added to the system the overall level of emissions is reduced. Due to the variability and imperfect predictability of resources like wind power, dispatchable resources may need to be utilized in different operational modes that in some instances and/or during some hours may actually increase these units' emissions rates (in terms of tons of emittant per MWh of electrical energy), however the total emissions of the system will be reduced. The effects of the increases in marginal emissions rates are expected to be several orders of magnitude smaller than the effect of the overall reductions in emissions. Reduced frequency and/or capability of external interchange limits the ability of balancing areas to share some of the effects of wind power's variability and uncertainty with neighboring systems that at any given time might be better positioned to accommodate these effects. Practices that limit the ability of resources to participate in the power system markets to the full extent of their technical capability may cause the system to operate in a constrained manner, which reduces system flexibility. Self-scheduled generation reduces the flexibility of the dispatchable generation resource and can lead to excessive wind curtailment at higher penetrations of wind generation. It is recommended that ISO-NE examine its policies and practices for self-scheduled generation, and possibly change those policies to encourage more generation to remain under the control of ISO-NE dispatch commands. System flexibility can also be negatively impacted due to expected as well as unforeseen operational conditions of the system that reduce the ability to access and/or utilize the technical flexibility of the system resources. Examples of operational conditions that can negatively impact system flexibility include the long-term outage of resources that provide a large portion of the flexibility on the system, and chronic transmission system congestion or stability and/or voltage constraints along important transmission corridors.

Operating Records: It is recommended that ISO-NE record and save sub-hourly data from existing and new wind plants. System operating records, including forecasted wind, actual wind, forecasted load, and actual load should also be saved. Such data will enable ISO-NE to benchmark actual system operation with respect to system studies. ISO-NE should also periodically examine and analyze this data to learn from the actual performance of the ISO-NE system.

Other Observations from Study Results

Flexible Generation: The ISO-NE system presently has a high percentage of gas-fired generation, which can have good flexibility characteristics (e.g., ramping, turn-down). Using the assumed system, the results showed adequate flexible resources at wind energy penetration levels up to 20%. Also using the assumed system, there are periods of time in the 24% wind energy scenario when much of the natural-gas-fired generation is displaced by the wind generation, leaving less flexible coal and nuclear operating together with the wind generation. In this study, physical limits were used to determine how much units could be turned down when system conditions required such action. ISO-NE will need to be diligent in monitoring excessive self-scheduling, which could limit the apparent flexibility of the generation fleet. ISO-NE may need to investigate operating methods and/or market structures to encourage the generation fleet to make its physical flexibility available for system operations (See Section 5.2.1.2).

Energy Storage: Study results showed no need for additional energy storage capacity on the ISO-NE system given the flexibility provided by the assumed system. However, the need for energy storage may increase if there is attrition of existing flexible resources needed to balance net load and dispatchable resources. It is commonly believed that additional storage is necessary for large-scale wind integration. In New England, wind generation displaces natural-gas-fired generation during both on peak and off-peak periods. Natural-gas-fired generation remains on the margin, and the periodic price differences are usually too small to incent increased utilization of pumped storage hydro-type energy storage, which is why the study results showed PSH utilization increasing only slightly and only at higher levels of wind penetration.

Additional energy storage may have some niche applications in regions where some strategically located storage facilities may economically replace or postpone the need for transmission system upgrades (i.e., mitigate congestion). Also, minute-to-minute type storage may be useful to augment existing regulation resources. But additional large-scale economic arbitrage type storage, like PSH, is likely not necessary (See Section 5.2.1).

Displacement of Energy from Conventional Generation: Energy from wind generation in New England primarily displaces energy from natural-gas-fired generation. Although displacement of fossil-fueled generation might be one of the objectives of regional energy policies, a consequence is that it may radically change the market economics for all resources on the system, but especially for the natural-gas-fired generation resources that are displaced. Although their participation in the ISO-NE market will continue to be important, to serve both energy (especially during summer high-load periods) and capacity requirements, the balance of revenues that resources receive from each of these market segments will change. Since total annual energy output from conventional resources would decline and energy prices also would decline under the study assumptions, capacity prices from these plants will likely need to increase if they are to remain economically viable and therefore able to provide the flexibility required for efficient system operation (See Section 5.2.1).

Dynamic Scheduling: Dynamic scheduling involves scheduling the output of a specific plant or group of plants in one operating area on transmission interties to another operating area. Dynamic scheduling implies that the intertie flows are adjusted on a minute-to-minute basis to follow the output of the dynamically scheduled plants. Most scenarios in this study included all necessary New England wind resources within the ISO-NE operating area, and therefore did not require dynamic scheduling. The Maritimes scenarios assumed that a portion of the ISO-NE wind generation would be imported from wind plants in the Canadian Maritimes using dynamic scheduling, so that ISO-NE would balance the variability due to the imported wind energy. The results showed, given the study assumptions, that ISO-NE has adequate resources to balance the imported Maritimes wind generation.

Load and Distributed Wind Forecasting: This study assumed that load forecast accuracy would remain the same as wind penetration increases. However, a portion of the wind generation added to the ISO-NE system will be distributed generation that may not be observed or controlled by ISO-NE. It will essentially act as a load-modifier. As such, distribution-connected wind generation will negatively affect the accuracy of load forecasts. As long as the amount of this distribution-connected wind generation is fairly small and if ISO-NE is able to account for the magnitude and location of distribution-connected wind plants, it should be possible to include a correction term into the load-forecasting algorithm (See Section 5.3.3).

Technical Requirements for Interconnection of Wind Generation

The Task 2 report, "Technical Requirements for Wind Generation Interconnection and Integration," includes a set of recommendations for interconnecting and integrating wind generation into the ISO-NE power grid. That report was completed before the statistical, production simulation, and reliability analyses of the NEWIS scenarios were performed. The recommendations contained in the Task 2 report were re-examined after the NEWIS scenario analysis was completed and the analysis performed reinforces the need to implement those recommendations. It was determined that no changes to the Task 2 recommendations are warranted at this time based on the results of the scenario analysis. A few of the most significant Task 2 recommendations are summarized below.

Active Power Control: Wind plants must have the capability to accept real-time power schedule commands from the ISO for the purpose of plant output curtailment. Such control would most often be used during periods when wind generation is high and other generating resources are already at minimum load.

AGC Capability: Wind plants should be encouraged to have the capability to accept Automatic Generation Control (AGC) signals, which would enable wind plants to provide regulation. The current ISO-NE market product requires symmetrical regulation, which means that wind generation could only provide this service when it is curtailed. Some other systems have asymmetrical regulation markets where wind generation could be quite effective at down-regulation even under non-curtailed operation, such as when other generation resources have been dispatched down to minimum load and/or other down regulation resources have been exhausted.

Centralized Wind Forecast: ISO-NE should implement a centralized wind power forecasting system that would be used in a manner similar to the existing load forecasting system. Information from the day-ahead wind forecast would be used for unit commitment as well as scheduling regulation and reserves. ISO-NE should also implement intra-day forecasting (e.g. an early warning ramp forecasting system) that will provide improved dispatch efficiency and situational awareness, and alert operators to the likelihood and potential magnitude and direction of wind ramp events.

Communications: Wind plants should have the same level of human operator control and supervision as similar sized conventional plants. Wind plants should also have automated control/monitoring functions, including communications with ISO-NE, to implement operator commands (active/reactive power schedules, voltage schedules, etc.) and provide ISO-NE with the data necessary to support wind forecasting functions. The Task 2 report contains detailed lists of required signals.

Capacity Value: Given that only three years of data were available for the LOLE calculation and that the results of this method can vary somewhat from year to year, it is recommended that ISO-NE should monitor a comparison between its current approximate method and the ELCC method for determining the aggregate capacity value of all wind generation facilities in the operating area, and the calculation should be updated periodically as operational experience is gained. Historical data should be used for existing plants; data from mesoscale simulations could be used for new plants until sufficient operation data is available.

If the recommendations developed and discussed in the Task 2 report are not implemented, it is highly likely that operational difficulties will emerge with significant amounts of wind generation. Two recent examples of some Balancing Authorities experiences with a lack of effective communication and control and/or a lack of an effective wind power forecast and the resulting operational difficulties include having to:

- Implement load-shedding[14] (albeit contracted-for load-shedding), and
- Spill water for hydro resources.[15]

Another example of operational difficulties that could arise includes the experience of some European TSO's with older windplants' lack of ability to participate in voltage control causing the system to sometimes be operated in very inefficient dispatch modes. This lack of voltage control participation, as well as the lack of communication and control capability, was found to have exacerbated the severe European UCTE disturbance in November of 2006[16].

Future Work

Several areas of interest that are candidates for further investigation are suggested by the study results. These include:

Transmission system overlay refinement. The transmission system overlays developed for the Governors' Study and used in this study were shown, based on thermal limit analysis only, to have adequate capacity for all scenarios. In fact, some NEWIS scenarios use transmission overlays that were "one size smaller" than those used for the Governors' Study scenarios, and still no or only minimal congestion was observed. Detailed and extensive transmission studies that include stability and voltage limits will be required in order to proceed with specific wind projects or large-scale wind integration.

A future study could start by analyzing wind penetration scenarios using a "copper sheet" approach to evaluate magnitude and duration of congestion due to existing transmission limitations. This would guide the design of specific transmission additions to minimize congestion with increased levels of wind generation.

Sub-hourly performance during challenging periods. A more in-depth investigation of the dynamic performance of the system under conditions of high stress, such as coincident high penetration and high variability could be pursued using additional simulation tools that have

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[14] ERCOT Event on February 26, 2008: Lessons Learned, available at: http://www1.eere.energy.gov/windandhydro/pdfs/43373.pdf.

[15] "Wind power surge forces BPA to increase spill at Columbia Basin dams" available at: http://www.oregonlive.com/environment/index.ssf/2008/07/columbia_basin_river_managers.html

[16] Final report: System Disturbance on 4 November 2006, available at: https://www.entsoe.eu/fileadmin/user_upload/_library/publications/ce/otherreports/Final-Report-20070130.pdf

been developed recently. Both long-term dynamic (differential equations) simulations and fine time resolution quasi-static time simulations could shed additional insight into the frequency, ACE, CPS2 and other performance measures of the system, as well as providing more quantitative insight into incremental maneuvering duties imposed on the incumbent generation and the impacts of this increased maneuvering on such quantities of interest as emissions and increased generator maintenance. Such analysis could be part of an assessment of possible increased operating costs associated with maneuvering (beyond those captured in the MAPS analysis).

Impacts of Cycling and Maneuvering on Thermal Units. Costs of starting and stopping units, and static impacts on heat rate were reflected in the study to the extent presently possible. However, the understanding of these impacts and the quantification of costs is still inadequate throughout the industry. A deeper quantification of the expected cycling duty, the ability of the thermal generation fleet to respond and an investigation of the costs – O&M, emissions, heat rate, and loss-of-life – would provide clearer guidance for both operating and market design strategies.

Economic Viability and Resource Retirements. The incumbent generating resources, particularly natural-gas-fired generation, will be strongly impacted by large-scale wind generation build-outs like those considered in the study. Investigation should be performed to determine the revenue impacts, and their implications for the long-term viability of the system resources that provide the flexibility required to integrate large-scale wind power. Such investigation could include examination of impact of possible resource retirements driven by reduced energy sales and revenues, and the efficacy of possible market structures for maintaining the necessary resources to maintain system reliability.

Demand Response. A deeper analysis of the efficacy and limitations of various demand-side options for adding system flexibility could help define directions and policies to pursue. Temporal aspects of various demand response options could be further investigated. For example, heating and cooling loads have significant time and duration constraints that will govern their effectiveness for different classes of response. Similarly, some types of commercial and industrial loads may offer options and limitations for providing various ancillary services that will be needed.

Weather, Production, and Forecasting Data. This study was based on sophisticated meso-scale wind modeling. The ISO should start to accumulate actual field data from operating wind plants, from met masts, and from actual forecasts. Further investigation and refinement of study results or use of such data in the suggested sub-hourly performance analysis, would increase confidence in results and may allow for further refinement of ISO plans and practices.

Network Planning Issues. This study was not a transmission planning study. The addition of significant wind generation, particularly multiple plants in close electrical proximity in parts of the New England grid that may be otherwise electrically remote (for example the addition of significant amounts of wind generation in Maine) poses a spectrum of application questions. A detailed investigation of a specific subsystem within New England considering local congestion, voltage control and coordination, control interaction, islanding risk and mitigation, and other engineering issues that span the gap between "interconnection" and "integration" would provide insight and help establish a much needed set of practices for future planning in New England (and elsewhere).

1 Introduction

1.1 Overview of ISO-NE

ISO New England Inc. (ISO-NE) is the not-for-profit corporation that serves as the Regional Transmission System Operator (RTO) for New England. ISO-NE is responsible for the reliable operation of New England's power generation, demand response and transmission system, administers the region's wholesale electricity markets, and manages the comprehensive planning of the regional power system. ISO-NE has the responsibility to protect the short-term reliability and plan for the long-term reliability of the Balancing Authority Area, a six-state region that includes approximately 6.5 million businesses and households.

The New England electricity market consists of an energy market (i.e., Day-Ahead and Real-Time Energy Markets), ancillary services markets (i.e., Forward Reserve Market and Regulation), and a capacity market (i.e., Forward Capacity Market). Through these competitive wholesale markets, the ISO ensures the availability of electricity to meet the demands of the region.

Through the Day-Ahead Energy Market (DAM) and Real-Time Energy Market (RTM), the ISO coordinates the commitment and dispatch of resources by economically scheduling resources to provide energy and ancillary services on the basis of supply offers, bid-in load, submitted transactions, and transmission information. The DAM produces financially binding obligations. Resources generally are committed to operate in real-time consistent with their DAM schedule. To the extent that insufficient resources clear in the DAM to meet ISO-NE's forecasted real-time load or expected real-time reliability requirements, ISO-NE commits additional resources in the RTM, which is effectively a balancing market. In real-time, the dispatch and scheduling software co-optimizes the dispatch of resources to provide energy and operating reserves. The ISO also runs the Regulation Market in real-time, which schedules resources to provide regulation services. Dispatch instructions are sent out to all of the resources in the New England Balancing Authority Area consistent with their offer data, limits, and constraints to meet changing load and ancillary service requirements throughout the Operating Day.

Commitment and dispatch of the system is done on five-minute intervals using a security constrained economic commitment and dispatch. This approach recognizes transmission constraints in the commitment and dispatch solutions. Both the DAM and RTM generate Locational Marginal Prices (LMP), which reflects the marginal cost of meeting the next increment of load at a location while respecting transmission constraints. The RTM also produces locational reserve prices by reserve category and system-wide regulation prices. The reserve prices reflect the opportunity cost of re-dispatching the system to maintain reserves. Regulation prices reflect the offer of the most expensive resource selected to provide regulation in an hour.

The ISO also administers a Forward Capacity Market (FCM) and a Locational Forward Reserve market. The FCM is a forward market for physical resources through which the ISO procures an amount of capacity equal to the Installed Capacity Requirements (ICR) for New England three years prior to the time the capacity is needed. The Locational Forward Reserve Market (FRM) is the mechanism by which the ISO procures reserve capacity in New England for dispatch during system contingencies.

Intermittent Power Resources[17] (IPRs) (e.g. wind power) are not required to participate in the DAM, but are permitted to do so. Regardless of whether or not they offer into the DAM, Intermittent Power Resources are not subject to deviations or imbalance charges in the RTM; though if IPRs choose to participate in the DAM they must make up any shortfall in production by purchasing power in real-time. The Market Rules also allow IPRs to participate in the FCM by having mechanisms in place through which ISO-NE can confirm the claimed capacity ratings of the IPRs for the purpose of qualifying in the Forward Capacity Auction (FCA).[18]

1.2 Key Drivers of Wind Power

The large-scale use of wind power is becoming a norm in many parts of the world. The increasing use of wind power is due to the emissions-free electrical energy it can generate; the speed with which wind power plants can be constructed; the generation fuel source diversity it adds to the resource mix; the long-term fuel-cost-certainty it possesses; and, in some instances, the cost-competitiveness of modern utility-scale wind power. Emissions-free generation helps meet environmental goals, such as Renewable Portfolio Standards (RPS)[19] and greenhouse gas

[17] See ISO Tariff, Section I.2 (defining "Intermittent Power Resources" to include those resources "whose output and availability are not subject to the control of the ISO or the plant operator because of the source of fuel (e.g., wind, solar, run-of-river hydro)," among others).

[18] See id. at Section III.13.1.1.2.2.6.

[19] Each state in New England has adopted a renewable portfolio standard, except for Vermont, which has set renewable energy goals. RPSs set growing percentage-wise targets for electric energy supplied by retail suppliers to come from renewable energy sources. For a further description of New England related policies potentially affecting wind power see, for example, the ISO-NE Regional System Plan. RSP10 is available at: http://www.iso-ne.com/trans/rsp/index.html.

control. Once the permitting process is complete, some wind power plants can be constructed in as little as three to six months, which facilitates financing and quick responses to market signals. Wind power, with a fuel cost fixed at essentially zero, can contribute to fuel-cost certainty and would reduce New England's dependence on natural gas. In New England, the economics of wind power are directly affected by the outlook for the price of natural gas; higher fuel prices generally spur development of alternative energy supplies while lower fuel prices generally slow such development. Wind power development also is directly affected by environmental policy drivers such as restrictions on generator emissions or renewable energy generation targets.

While wind can provide low-priced zero-emissions energy, the variability of wind resources and the uncertainty with which the amount of power produced can be accurately forecasted poses challenges for the reliable operation and planning of the power system. Many favorable sites for wind development are remote from load centers. Development of these distant sites would likely require significant transmission development, which may not appear to be economical in comparison to conventional generation resources (at current prices) and could add complexity to the operations and planning of the system. The geographical diversity of wind power development throughout New England and its neighboring systems in New York and the eastern Canadian provinces would mitigate some of the adverse impacts of wind resource variability if the transmission infrastructure, operating procedures, and market signals were in place to absorb that variability across a larger system. Several Elective and Merchant Transmission Upgrades are in various stages of consideration to access these wind and other renewable resources.

1.3 Growth of Wind Power in New England

As of October 2010, approximately 270 megawatts (MW) of utility-scale wind generation are on line in the ISO New England system, of which approximately 240 MW are biddable assets. New England has approximately 3,200 MW of larger-scale wind projects in the ISO Generator Interconnection Queue more than 1,000 MW of which represent offshore projects and more than 2,100 MW of which represent onshore projects.[20] The wind capacity numbers in the ISO queue are based on nameplate ratings. Figure 1–1shows a map of planned and active wind projects in New England. As an upper bound of all potential wind resources—and not including the

[20] The 3,200 MW of wind in the queue is as of October 1, 2010, and includes projects in the affected non-FERC queue.

feasibility of siting potential wind projects—New England holds the theoretical potential for developing more than 215 gigawatts (GW) of onshore and offshore wind generation.[21]

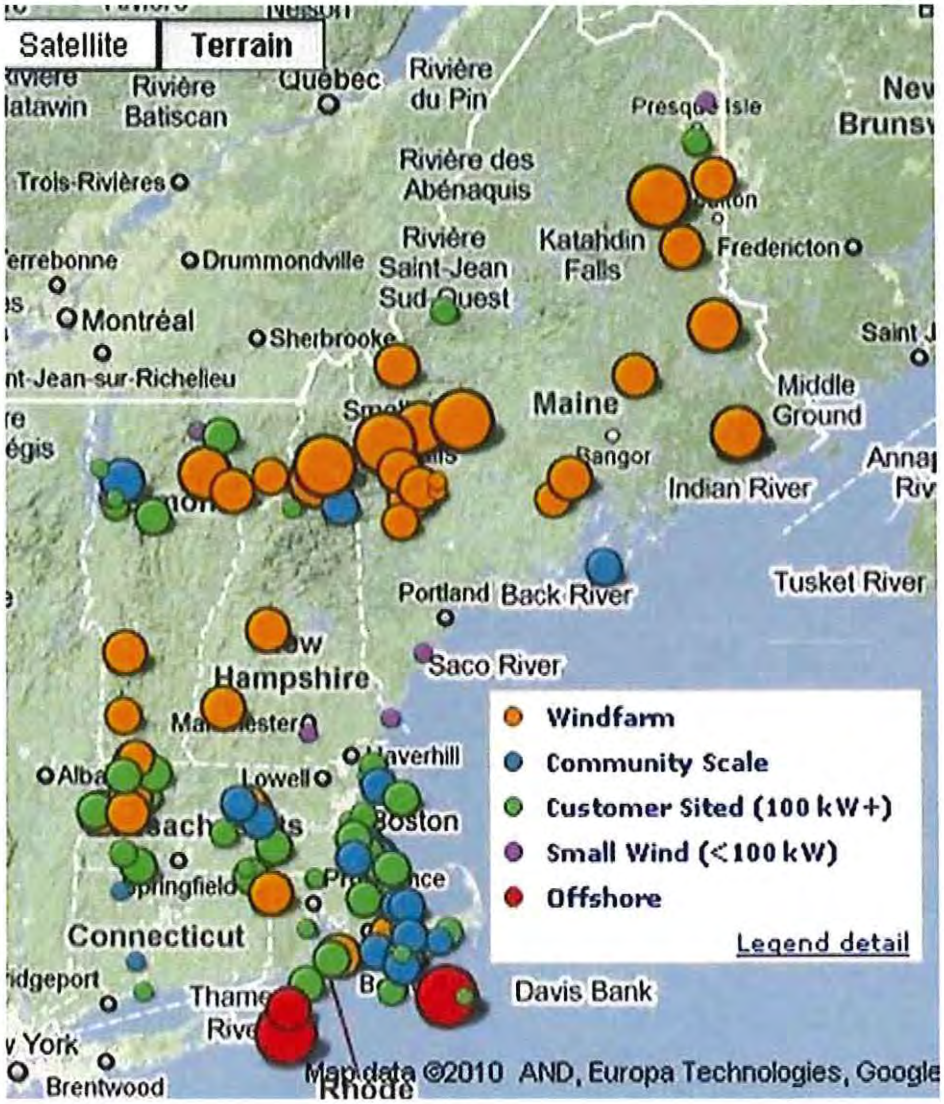

Figure 1–1 Planned and active wind projects in New England, 2010. Source: Sustainable Energy Advantage

1.4 The Governor's Economic Study

In 2009, the ISO completed the Scenario Analysis of Renewable Resource Development (the "Governors' Economic Study") – a comprehensive analysis for the integration of renewable

[21] 2009 Northeast Coordinated System Plan (May 24, 2010); http://iso-ne.com/committees/comm_wkgrps/othr/ipsac/ncsp/index.html.

resources over a long-term horizon, performed at the request of the Governors of the six New England states.[22] The Governors' Economic Study identified economic and environmental impacts for a set of scenario analyses that assumed the development of renewable resources in New England. The study also identified the potential for significant wind power development in the New England states, the effective means to integrate this wind power development into the grid, and related preliminary transmission cost estimates, it did not evaluate operational impacts. Certain scenarios analyzed in the study indicated that, through development in the Northeast, New England and its neighbors could effectively meet the renewable energy goals of the region. Other scenarios showed that the region could be a net exporter of renewable energy.

The Governors' Economic Study ultimately informed the New England Governors' Renewable Energy Blueprint (the "Blueprint"), adopted last year by the six New England state governors.[23] The Blueprint sets forth policy objectives for the development of renewable resources in the Northeast that could ultimately lead to substantial penetration of wind power in New England.

1.5 Operational Effects of Large-scale Wind power

Large-scale wind integration adds complexity to power system operations by introducing a potentially large quantity of variable-output resources and the new challenge of forecasting wind power in addition to load.

The power system is designed and operated in a manner to accommodate a given level of uncertainty and variability that comes from the variability of load and the uncertainty associated with the load forecast as well as the uncertainty associated with the outage of different components of the system, such as generation or transmission. Due to a long familiarity with load patterns and the slowly changing nature of those patterns, the variability of the load is quite regular and well understood. The result is that the power system has been planned to ensure that different types of resources are available to respond to the variability of the load (e.g., baseload, intermediate, and fast-start resources have come into service) and the uncertainty associated with the load forecast is generally very small. The uncertainty associated

[22] The Governor's Economic Study is available on the ISO's website at: http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/index.html.
The Governor's Economic Study was conducted pursuant to the Regional System Planning Process established in Attachment K of the ISO OATT.

[23] See Blueprint Materials, available at: http://www.nescoe.com/Blueprint.html.

with equipment outages is of a more discrete and "event" type nature that can be handled in a relatively deterministic fashion. This is the basis of contingency analysis where lists of credible contingencies are evaluated on a frequent periodic basis for their effects on power systems operations.

The combination of wind power's variability and the uncertainty of forecasting wind power make it fundamentally different from analyzing and operating other resources on the system. The weather patterns that drive the generation characteristics for wind power vary across many timescales and are loosely correlated with load. For example, ISO-NE experiences its peak loads during the summer months, while, as observed in this study, wind generation produces more energy during the winter months than in the summer. The uncertainty associated with wind generation is very different from the uncertainty associated with typical dispatchable resources. In general, uncertainty of energy supply from dispatchable conventional generation is due to forced unit outages due to equipment failures or other discrete events. Uncertainty in wind generation is more like uncertainty due to load. The amount of wind generation expected for the next day is forecasted in advance (just as load is forecasted in advance), and the amount of wind generation that actually occurs may be different from the forecasted amount, within the accuracy range of the forecast. In contrast, however, to forecasting of day-ahead load where typical average error is on the order of 1% to 3% Mean Absolute Error (MAE); the accuracy of state-of-the-art day-ahead wind forecasts is in the range of 15% to 20% MAE of installed wind rating. For small amounts of installed wind, load uncertainty dominates, but at higher penetrations of wind, forecast uncertainty becomes very important. In order to plan for the reliable operation of the power system, it is important to study how this combination of variability and associated uncertainty will affect power system operations far enough ahead of time for the effects to be quantified and any required mitigation measures to be put into service.

The loose correlation of wind and load requires the use of a new metric, "net load," to study the impact of large-scale wind generation where the fleet of dispatchable resources is used to balance the time-synchronous variability and uncertainty of the load minus the output of the wind generation. When managing the power system, the output of variable resources such as wind power can be directly subtracted from the amount of load to be served, the dispatchable resources on the system are then used to serve this remaining (i.e., "net") load in order to maintain the power system balance. The net load is then the true variability that must be managed with dispatchable resources and therefore it is the net load that must be studied when determining operational effects.

1.6 NEWIS Tasks and Analytical Approach

Anticipating the possible penetration of large-scale wind power in New England, ISO-NE also commissioned this comprehensive wind integration study in 2009 – the New England Wind Integration Study (the NEWIS) – to assess the operational effects of large-scale wind penetration in New England using statistical and simulation analysis of historical data.[24], [25] By focusing on the operational effects of large-scale wind integration, the NEWIS complements and builds on the results of the Governors' Economic Study.

The goals of the NEWIS were to determine the operational, planning and market impacts of integrating substantial wind generation resources for the New England Balancing Authority Area, with due consideration to the neighboring areas, as well as, the measures that may be available to ISO-NE for mitigating any negative impacts while enabling the integration of wind. The NEWIS also sets forth recommendations for implementing these measures. Additionally, the NEWIS identifies the potential operating conditions created or exacerbated by the variability and unpredictability of wind generation resources, and recommends potential corrective activities, recognizing the unique characteristics of the tightly integrated bulk power system in New England and the characteristic of wind generation resources. Consistent with the Governors' Economic Study, the NEWIS examines various scenarios of increasing wind power penetration up to approximately 12 GW of nameplate wind power.

In order to accomplish its goals, the NEWIS captures the unique characteristics of New England's bulk electrical system including load and ramping profiles, geography, system topology, supply and demand-side resource characteristics, and wind profiles and their unique impacts on system operations and planning with increasing wind power penetration. To facilitate the work of the NEWIS, it is broken into five tasks:

1. Wind Integration Study Survey
2. Technical Requirements for Interconnection
3. Mesoscale Wind Forecasting and Wind Plant Models

[24] See NEWIS Materials, New England Wind Integration Study (NEWIS) Wind Scenario and Transmission Overlays, available at: http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2010/jan212010/newis.pdf.

[25] The core project team included GE Energy Applications and Systems Engineering, EnerNex, and AWS Truepower. Many members of this team have extensive experience and have been among the pioneers of wind integration analysis.

4. Scenario Development and Analysis

5. Scenario Simulation and Analysis

The first task – Wind Integration Study Survey – involved a review of the experience gained and lessons learned from several previous domestic and international wind integration studies on bulk electric power systems (including ISO-NE studies such as phases I and II of the Technical Assessment of Onshore and Offshore Wind Generations Potential in New England (2007, 2008)[26] and the New England Electricity Scenario Analysis (2007)[27]) and actual wind integration experiences in bulk electric power systems. This task was completed with a presentation at the NEWIS project kickoff meeting. The project team has considered this information while developing detailed work plans for the other tasks.

The second task – Technical Requirements for Interconnection – includes the development of specific recommendations for technical requirements for wind generating resources. This task looks at wind power plants' ability to provide grid support functions such as their capability to reliably withstand low-voltage conditions, provide voltage support to the system, adjust megawatt output to support the operation of the system, provide ancillary service type products (e.g. regulation), and coordinate with other equipment and control schemes during disturbances. This task includes data and telemetry requirements, maintenance and scheduling requirements, high wind cutout behavior, and the development of best practice methods of the Effective Load Carrying Capability (ELCC) calculation used for establishing capacity values for global and incremental wind generation. This task also investigates and recommends wind power forecasting methods for both the very short-term timeframe (useful in real-time operations) and the short- to medium-term timeframe (useful in unit dispatch and day-ahead unit commitment), as well as the required accuracy for wind power forecasts, and implementation issues. This task was completed in fall 2009, with recommendations to ISO-NE detailed in a "Technical Requirements for Wind Generation Interconnection and Integration" report (the "NEWIS Technical Report").[28]

[26] Available on ISO-NE's website located at: http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2008/may202008/

[27] Available on ISO-NE's web site located at: http://www.iso-ne.com/committees/comm_wkgrps/othr/sas/mtrls/elec_report/

[28] See NEWIS Technical Report, available at: http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2009/newis_report.pdf. ISO-NE presented the recommendations

The third task – the Mesoscale Wind Forecasting and Wind Plant Models – was completed at the end of calendar year 2009. This task consists of the development of an accurate and flexible mesoscale hindcasting model for the New England and Maritime wind resource area (including offshore wind resources) that allows for the simulation of power system and wind generation operations and interactions (e.g., unit commitment, scheduling, load following, and regulation) over the timescales of interest. The model is designed to produce three years of realistic time-series of wind data in order to quantify the effects of inter-annual variability in wind generation and system-wide load. The database of wind resource and power data developed for the NEWIS along with a tool for interrogating and aggregating this database has been transferred to ISO-NE. This tool allows reuse of the mesoscale modeling data for further ISO-NE studies.

The fourth task – Scenario Development and Analysis – develops base case and wind generation scenarios in consultation with ISO-NE and stakeholders that includes potential and probable scenarios for wind power development for scenarios considering various levels of wind development: from wind power projects that are active and in advanced stages of the planning process (approximately 1.14 GW, nameplate) up to 20% to 24 % of the projected annual consumption of electric energy (approximately 9 GW to 12G W, nameplate). This task then builds on and expands the knowledge gained and tools developed in the tasks 1, 2, and 3 and the developed scenarios to perform a detailed evaluation of the impact of incremental wind generation variability and uncertainty on New England's bulk electric power system via statistical measures.

The fifth task – Scenario Simulation and Analysis – develops simulations and analysis of these scenarios in order to assess the measures needed to successfully integrate substantial wind generation, respectively. The simulations evaluate the use of on-line generation for day-ahead commitment, economic dispatch, load following, regulation, and contingency reserves; the production of air emissions; the effects of carbon cost; and the effects on LMPs. Sensitivity analyses include the impacts of varying levels of diversity of the wind portfolio on the performance of the electric power system.

The final two tasks – task four and five– were partially performed in parallel and completed in the fall of 2010.

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of the NEWIS Technical Report to New England stakeholders at the November 18, 2009 meeting of the Planning Advisory Committee ("PAC"). *These recommendations will be subject to the applicable stakeholder processes prior to implementation.*

The analysis performed in the NEWIS is both qualitative and quantitative, and is meant to provide a basis to judge whether the New England power system has adequate resources (supply and demand-side) to reliably incorporate a large amount of wind-generated power. Neighboring control area systems and wind power development will also influence ISO-NE's bulk electric power system and are therefore also represented in this study. Measures that would facilitate the integration of wind, such as changes to market rules, and the use of demand response also are studied. The evaluation also includes a review of the ISO-NE's market design considering a high penetration of wind generation and how the scenarios could affect system reliability and/or contribute to inefficient market operation of the bulk electric power system. Ultimately, this analysis leads to recommendations for modifying existing procedures, guidelines, and standards to reliably and efficiently accommodate the integration of new wind generation.

The results of this report will form some of the basis for the ISO's policies and practices that may result in changes to the ISO Tariff, Operating and Planning Procedures and Manuals. As stated earlier, ISO-NE has presented the work completed to date to stakeholders, and will continue to work with stakeholders to discuss the study's findings, and then complete a full stakeholder process within New England prior to implementing any final recommendations in the form of rule and procedure changes to support the integration of wind power.

In order to be clear about the interpretation of the methods used, results obtained, and any recommendations provided, it is important to recognize what the NEWIS is and what it is not. The NEWIS is neither a transmission planning study nor a blueprint for wind power development in New England, and large-scale wind power development might or might not occur in the region. The NEWIS takes a snapshot of a hypothetical future year where low, moderate, and large wind power penetrations are assumed. Feedback dynamics in markets, such as the impact of overall reduced fuel use and the changes in fuel use patterns on fuel supply and cost, were not analyzed or accounted for. It is not a goal of ISO-NE to increase the amount of any particular resource; instead the ISO's goal is to provide mechanisms to ensure that it can meet its responsibilities (stated above) for operating the system reliably, managing transparent and competitive power system markets, and planning for the future needs of the system, while providing a means to facilitate innovation and the fulfillment of New England's policy objectives. In this context the NEWIS is meant to investigate whether there are any insurmountable operational challenges that would impede ISO-NE's ability to accept large amounts of wind generation.

A fundamental assumption in the NEWIS is that the transmission required to integrate the hypothesized wind generation into the bulk power system would be available and that the wind power resources would interconnect into those bulk transmission facilities. The NEWIS is a system-wide transportation study and, as such, does not account for local issues. For example, even with the limited wind generation that currently exists on the ISO-NE system, there are some instances where local transmission constraints result in curtailment of wind facilities due to the typical development pattern of wind generation facilities in New England and their interconnection under the minimum interconnection standards process. Implementing the recommendations developed as a result of the NEWIS will not solve these issues, unless the aforementioned sizable transmission expansions were to be built and the wind generation facilities were to connect directly into those expansions.

Another important assumption is that the available portfolio of non-wind generation in New England and neighboring systems was held constant across all alternatives considered. Neither attrition nor addition of new non-wind generation was considered as modifications to the base case.

Furthermore, detailed and extensive engineering analysis regarding stability and voltage limits would be required in order to determine the viability of the hypothesized transmission expansions, which in themselves may require substantial effort to site and build. It is also important to note that implementing the recommendations developed during the second task of the NEWIS (e.g., wind power specific grid support functions, wind power forecasting, windplant modeling, and communications and control) are absolutely essential for the reliable integration of large-scale wind power into the New England power system.

Finally, in addition to the significant observations mentioned above, changes may be required to systems and procedures within the ISO organization that are yet to be determined. These changes would require additional analysis for increasing levels of wind penetration and for issues identified within New England, or beyond, as system operators gain experience with wind energy. The development, implementation, and operating costs associated with these changes are not accounted for in this study.

1.7 NEWIS Task Flow and External Review Process

Several levels of review were incorporated into the task flow of the NEWIS:

1. Stakeholder feedback (PAC)
2. Internal ISO-NE review (see Table 1–1)
3. Independent Technical Review Committee (TRC) of recognized experts (see Table 1–2)

Table 1–1 ISO-NE Team Members Participating in NEWIS

NEWIS ISO-NE Team Member	ISO NE Organization Unit/Title
Jon Black	System Operations, Intern
Wayne Coste	Resource Adequacy, Manager
Mike Henderson	Regional Planning & Coordination, Director
William Henson	System Operations, Senior Renewable Resource Engineer
Steven Judd	Area Transmission Planning, Engineer
Fred Letson	Renewable Resource Integration, Intern
Jonathan Lowell	Market Design, Principal Analyst
Xiaochuan Luo	Business Architecture & Technology, Principal Analyst
John Norden	System Operations, Director
James Platts	Regional Planning & Coordination, Lead Engineer
Mike Potishnak	System Operations, Principal Engineer

Table 1–2 Members of NEWIS Technical Review Committee

NEWIS TRC Member	Affiliation
Utama Abdulwahid	Senior Research Fellow at the University of Massachusetts Wind Energy Center (UMass WEC)
Michael Jacobs	NREL's National Wind Technology Center
Brendan Kirby	Consultant for AWEA, NREL, Oak Ridge National Laboratory (ORNL), Electric Power Research Institute, and various ISO/RTOs
Warren Lasher	ERCOT, Manager of Long-Term Planning and Policy
Michael Milligan	NREL's Systems Integration Team at the National Wind Technology Center
J. Charles Smith	Utility Wind Integration Group, Executive Director

The NEWIS external review process, consisting of the Technical Review Committee (TRC) and the Planning Advisory Committee (PAC), was designed to ensure the NEWIS study was guided by the highest quality of technical work and greatest accuracy of results, and that interested stakeholders had the opportunity to provide input to the NEWIS at key stages of the study. This external review process was intended to ensure that the NEWIS provides accurate, representative, and relevant results and information for New England. A total of six TRC meetings and eight PAC presentations were held throughout the NEWIS project.

The PAC is the regional forum for interested parties to provide input to ISO-NE concerning the assessment and development of the Regional System Plan (RSP) and the conduct of system enhancement and expansion studies.

The TRC was created specifically for the NEWIS and was designed and assembled in a manner consistent with recommendations of the Utility Wind Integration Group (UWIG) and the aggregate experience from previous wind integration studies. Collectively, the TRC provided expertise in all of the technical disciplines relevant to the study.

Table 1–3 is a chronological breakdown of all project milestones, including PAC and TRC meetings.

Table 1–3 NEWIS Milestones

Milestone/Meeting	Date	Description
PAC Review	12/17/2008	Project roll out
Release RFP	12/19/2008	N/A
Select Vendor	3/17/2009	GE & Enernex & AWS Truepower team was selected
Project Kickoff Meeting	4/7/2009	Reviewed overall task flowchart, TRC participation, discussed overall approach and requirements
TRC Kickoff Meeting	5/22/2009	Project overview, TRC Charter, Analytical Approach
Scenario Development	6/9/2009	Begin wind Scenario Development
Markets and Ops meeting	6/10/2009	Explain ISO-NE Market and Operations to Team GE
PAC Review	6/17/2009	Status update, present selected vendor, TRC, refined scope of work
TRC Meeting 2	7/1/2009	Review mesoscale assumptions, introduce TRC, project schedule
ISO Senior Management Review	8/4/2009	Update of project status; PowerPoint presentation covering workplan, scenarios, assumptions, and comparison with Governors' Study
PAC Review	8/19/2009	Present scenario framework and assumptions
TRC Meeting 3	10/20/2009	Scenario framework and assumptions partial queue and full queue defined
Task 2 Release & PAC Meeting	11/18/2009	Discuss Task 2 report, status update
TRC Meeting 4	12/9/2009	Review sites/scenarios, discuss transmission overlays, discuss interim statistical results and interim MAPS results
PAC Review	12/16/2009	Short recap of VAr management recommendations from Task 2
PAC Review	1/21/2010	Describe wind scenarios and transmission overlays
TRC Meeting 5	3/22/2010	Wind scenarios, transmission overlays
PAC Review	5/25/2010	Interim results, transmission/wind scenario pairings
TRC Meeting 6	8/5/2010	Final draft results
ISO Senior Management Review	10/22/2010	Final draft presentation
PAC Review	11/16/2010	Presentation of key findings and recommendations
Final Report	12/17/2010	Release final full report

2 Objectives and Technical Approach

2.1 Development of the New England Wind Resource Area Model

AWS Truepower (AWST) developed a mesoscale wind model for the NEWIS study area, referred to as the New England Wind Resource Area Model (NEWRAM). The development of NEWRAM is based on the work that AWST conducted as part of the Eastern Wind Integration and Transmission Study (EWITS),[29] for which AWST was engaged by the National Renewable Energy Laboratory (NREL) to develop the wind resource and wind power output data.[30] The resulting superset of simulated wind resource data is referred to as NREL's Eastern Wind Dataset and represents approximately 790 GW of potential future wind plant sites within the EWITS study area, shown in Figure 2–1. NREL's dataset includes almost 39 GW of potential wind resource within the New England region.

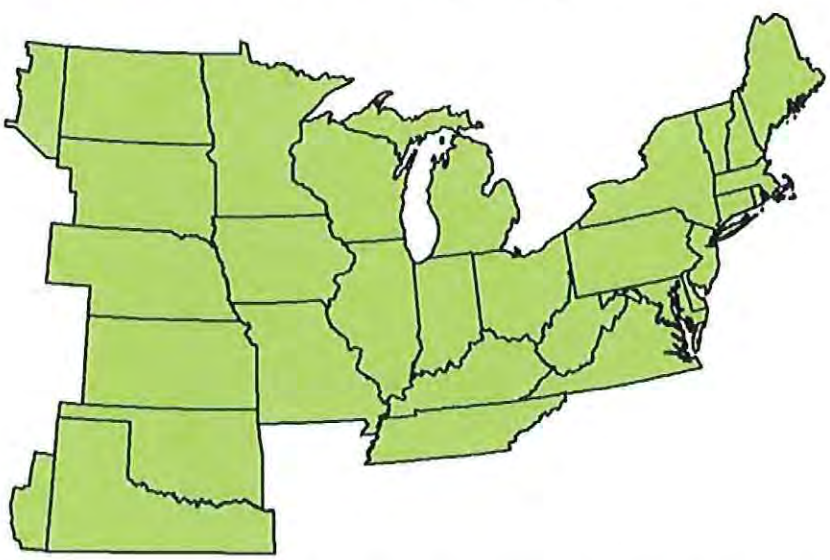

Figure 2–1 Eastern Wind Integration and Transmission Study (EWITS) study area. [from NREL report]

The ISO requested several alterations and additional features that are discussed in subsequent sections to provide more granularity and accuracy for the New England region. However, the

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[29] Information about the EWITS study can be found at http://www.nrel.gov/wind/systemsintegration/ewits.html

[30] For detailed information on EWITS data development refer to: Brower, 2009: Development of Eastern Regional Wind Resource and Wind Plant Output Datasets. NREL/SR-550-46764. Golden, CO: NREL.

basis for NEWRAM is the New England regional subset of the Eastern Wind Dataset superset. As such, description of NEWRAM begins with an overview of the Eastern Wind Dataset modeling process.

AWST's work for EWITS consisted of the following five technical tasks:

1. Develop simulated 10-minute wind data for the regional wind resource using mesoscale modeling
2. Assist NREL with site selection
3. Convert the selected wind resources to time series wind generation
4. Simulate wind forecasts for the selected wind plants
5. Develop simulated one-minute plant output data for select time intervals.

2.1.1 NREL Eastern Wind Dataset

2.1.1.1 Mesoscale Model Testing

AWST began by running subsets of three years to total one year's worth of hourly simulations of two mesoscale models in a variety of configurations, and comparing the resulting diurnal and seasonal trends to coincident measurements observed at 10 tall tower sites throughout the study area. Based on comparison of the models, AWST selected the Mesoscale Atmospheric Simulation System (MASS),[31] which is a proprietary numerical weather prediction model developed by AWST's partner, MESO, Inc. MASS uses data from a variety of geophysical[32] and meteorological databases to simulate atmospheric conditions over a specified interval and geographical area. In the finally selected configuration, AWST used the NCEP/NCAR Global Reanalysis (NNGR) dataset as the initializing data source, with rawinsonde and surface data assimilated in the course of the simulations.

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[31] MASS is a simplified computational fluid dynamics (CFD) model that is able to simulate complex wind flows in areas where ground measurements are nonexistent, and is designed to generate a highly detailed and realistic representation of wind resource.

[32] Geophysical data include topography, land cover, vegetation greenness, sea-surface temperatures, soil temperatures, soil moisture. Elevation data are from the Shuttle Radar Topographical Mission 30 Arc-Second Data Set (SRTM30). Land cover data are from the satellite-based Moderate Resolution Imaging Spectro-radiometer (MODIS) data set. The nominal spacing of all geophysical data sets is 1 km.

2.1.1.2 ***Mesoscale Simulations***

After selecting the model configuration, AWST conducted the mesoscale simulations of the historical climate for years 2004, 2005, and 2006[33] across the EWITS study area. Each year was run separately at a temporal and spatial resolution of 10-minutes and 2 km, respectively. For each 2 km cell, four files containing the following data were produced:

1. Surface pressure,
2. Temperature at 2 meters
3. Wind speed and direction, air density, and turbulent kinetic energy[34] (TKE) at a height of 80 meters
4. Wind speed and direction, air density, and TKE at a height of 100 meters

Data generated by the model constitute an instantaneous "snap-shot" of climatological conditions at each 10-minute time increment of the years simulated.

2.1.1.3 ***Selection of Sites – Exclusions and Wind Siting Assumptions***

The Eastern Wind Dataset site selection process was developed to identify the smallest "near-contiguous" areas sufficient to support the desired rated capacity, while also both meeting specified exclusion criteria and exhibiting the highest possible capacity factor. To conduct the site screening, AWST used predicted mean wind speeds at 80 meters from their proprietary MesoMap®[35] to generate a net capacity factor map. AWST's MesoMap® system is a hybrid of MASS and a microscale wind flow model that is used to simulate weather conditions for a representative meteorological year over a region of interest with a spatial resolution of 200 meters. For MesoMap®, MASS randomly samples daily data from a 15-year period so that each

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[33] The multi-year simulation period was selected to capture the effects of El Niño/Southern Oscillation (ENSO), which is a quasi-periodic climate pattern causing weather disturbances in North America. For the National Weather Center's archive of ENSO activity over the simulation period, see http://www.cpc.ncep.noaa.gov/products/expert_assessment/ENSO_DD_archive.shtml.

[34] Turbulent kinetic energy is meant to represent the smaller scale turbulent flows in the larger scale mean wind flows. Turbulent flow promotes mixing which increases average wind plant wind speeds, but also increases plant maintenance requirements.

[35] For detailed information on AWST's MesoMap® system, see: Brower et al, 2004: Mesoscale Modeling as a Tool for Wind Resource Assessment and Mapping. Proceedings of the 14th Conference on Applied Climatology, Boston, MA: American Meteorology Society, 7 pp.

month and season is represented equally, resulting in a non-contiguous hourly time series of wind and other weather variables. The results are summarized and input into the WindMap program, and then validated and adjusted (if necessary) with respect to wind measurements gathered from stations located in the region of interest. Data contained in the MesoMap® database include annual and monthly wind speed frequency distribution, diurnal wind speed distribution, and the directional distribution of the wind (i.e., wind rose[36]) associated with each 200-meter grid cell.

By using a GIS mapping process, exclusion criteria were developed and applied to the regional wind resource to account for land use restrictions and obtain a realistic representation of the sites most likely to be developed. Data from the United States Geological Survey (USGS) National Land Cover Database (NLCD)[37] and ESRI database[38] were utilized to map exclusion areas covering the following criteria:

Onshore Sites:

- Open Water
- 200 meter buffer of Developed Low Intensity
- 500 meter buffer of Developed Medium Intensity
- 500 meter buffer of Developed High Intensity
- Woody Wetlands
- Emergent Herbaceous Wetland
- Parks
- Parks Detailed
- Federal Lands (non – public)
- 10,000 ft buffer of small airports (all hub sizes)

[36] A wind rose is a diagram of both the percent of total time and mean wind speed from each azimuthal wind direction, usually measured in 22.5 degree increments. Sometimes percent of total estimated wind energy from each direction is also shown.

[37] NLCD is a 21-class land cover classification system applied consistently over the United States. The spatial resolution of the data is 30 meters. For more information see: http://www.mrlc.gov/nlcd.php.

[38] ESRI databases are geodatabases that serve data directly to web map server software developed by ESRI, called ArcGIS Internet Map Server. Mapped databases cover a broad range of information including land uses, demographical, and topographical data.

- 20,000ft buffer of large airports (medium and large hub sizes)
- Elimination of slopes greater than 20%

Offshore Sites:

- Sites must have a capacity factor of 32% or greater at 80 meters hub height
- At least 8 km from mainland for all states
- Water depths must be less than or equal to 30 meters

Onshore exclusion criteria were chosen in anticipation that the "best" onshore sites will be the ones developed first. The criteria were meant to steer site selection away from restrictive land uses and areas where wind development is either not viable or would be uneconomical. For instance, the increased technical challenge of installing turbines on extreme grades, coupled with the additional mechanical stress and fatigue that up flowing wind (a characteristic of the wind resource on steeper slopes) introduces on turbine components, makes these locations less desirable for wind development. Similarly, offshore exclusion criteria were selected to avoid potential barriers to development, and as such are designed to minimize visual impacts and represent the state of the art in industry standards concerning water depth. Offshore exclusion criteria concerning waves and currents were not included.

Using a floor capacity value of 22% for onshore wind power plants, sites with a local maximum capacity factor, at least 100 MW capacity and spacing no closer than 2 km to nearby sites were selected. AWST estimated a wind power density ranging from 8 MW/km2 to 20 MW/km2 based on the shape of each site. Due to the scarcity of sites in several states including Connecticut and Rhode Island, a separate site screening with a lower capacity factor threshold (approximately 13.5%) was conducted for those states. With the addition of these lower capacity sites, the result was a comprehensive set of more than 7,800 sites with a corresponding nameplate capacity of over 3,000 GW. NREL manually selected the final set of sites to ensure that a diverse set of scenarios could be developed for the Eastern Wind Dataset, with all states and regions well represented. NREL's selection process was based on setting capacity factor thresholds for each state that reduced the total set to match target statewide capacities. A set of 1,326 sites with a range of rated capacities totaling over 580 GW was used as the final pool to select from in developing the Eastern Wind Dataset wind scenarios.

AWST used mean 80-meter wind speeds to identify potential offshore sites with an estimated net annual capacity factor of at least 32%. Due to the spatial consistency of the offshore wind resource, these sites were grouped into 20 MW blocks representing 4 km^2 each with a mean wind power density of 5 MW/km^2. A total of more than 10,000 blocks representing almost 209

GW of potential wind plants were identified. Table 2–1 shows the breakdown of onshore and offshore sites for the Eastern Wind Dataset wind plants located in New England.

Table 2–1 Potential New England sites used for Eastern Wind Dataset

	Onshore Sites		Offshore Sites	
State	Count	Total MW	Count	Total MW
Connecticut	7	919	84	1680
Maine	42	5863	64	1280
Massachusetts	19	2166	1006	20120
New Hampshire	21	2371	1	20
Rhode Island	7	1039	65	1300
Vermont	17	2019		
Total	113	14377	1220	24400

2.1.1.4 Wind Plant Modeling and Resource-to-Power Conversion

Once the sites were selected, AWST used their proprietary program SynOutput to convert the atmospheric time-series data to wind plant output. Expected mean wind speeds for each site were taken from MesoMap® and adjusted to the year of simulation with respect to AWST's historical dataset spanning years 1997 to 2007. The mesoscale time series associated with each site was then scaled to match the expected mean wind speeds. Further adjustments were made to each site's diurnal and seasonal wind characteristic trends according to their correlation with corresponding trends of coincident measurements collected at the 10 validation stations. These adjustments were used to correct model biases.

Power curves were then developed for IEC Turbine Classes 1, 2 and 3 based on a composite of utility-scale, commercially available wind turbines. IEC Class 1 and 2 turbines are assumed to have a hub height of 80 meters; IEC Class 3 turbines are assumed to have hub height of 100 meters. SynOutput then applied the power curve for each turbine class to the time-series data for both hub heights at each site, and selected the most appropriate power output based on its estimated annual mean speed[39].

The following operational considerations were factored into SynOutput to ensure realistic conversion of the simulated meteorological data to wind plant power output:

- Wake loss estimation utilizing siting assumptions in conjunction with the prevailing wind direction determined from the simulated data.
- A random factor related to the TKE was used to account for wind gusts not explicitly simulated by the mesoscale model. Otherwise the simulated wind power time-series are too smooth.
- A normally distributed turbine availability with a mean of 94.8% and a standard deviation of 2.3%
- Three percent electrical losses
- Effects of spatial averaging on the fluctuating wind power
- The cumulative impact of these considerations resulted in total power losses at most sites between 15% to 17%, and a range of losses at all sites of 12% to 20%.

The results of the mesoscale modeling, site selection process, and power conversion were annual 10-minute time-series wind power data associated with each potential wind site for the years of 2004, 2005 and 2006.

2.1.1.5 ***Wind Forecasting Development***

Along with synthesizing wind data, AWST produced hourly forecasts for three different time horizons (next-day, six-hour, and four-hour) using their statistical forecast synthesis tool, SynForecast. The forecasts were intended to represent real forecasts generated by a state-of-the-art forecasting system for the years 2004, 2005, and 2006—the years of the simulated wind time-series. A typical state-of-the-art day-ahead forecast has a Mean Absolute Error (MAE) of 20%.[40]

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[39] The selection of the appropriate IEC turbine class is actually based on both the turbulence intensity (TI) and the extreme 10-minute average wind speed with a 50 year recurrence (Vref) at hub height. However, standards allow a multiplier of 5 to estimate Vref from the mean speed. Turbulence intensity is the expected value (at 15 m/s) of the standard deviation of the 10-minute average wind speed divided by the 10-minute average wind speed. Since simulated wind speeds are instantaneous, TI values could not be determined by AWST. Therefore, only the mean wind speed for each site was used to determine turbine class.

[40] For more information on state-of-the-art forecasting refer to the NEWIS Task 2 report.

In order to develop a realistic forecast, AWST first developed a set of transition probabilities for simulated plant output data using a Markov chain process,[41] and then used these transition probabilities to produce forecasts for four wind plants for which NREL had provided concurrent output data. AWST then validated the forecasts using statistical comparisons of the output data, the forecasts, and the forecast errors to check for systematic biases. After corrections were made to the next-day and six-hour-ahead forecasts to ensure that their relative forecast errors were realistic, the forecasting methodology was determined to be satisfactory and was used to generate forecasts for all wind plants in the Eastern Wind Dataset.

2.1.2 Alterations to the Eastern Wind Dataset for NEWIS

Although first proposed by AWST, ISO decided that the New England subset of the Eastern Wind Dataset needed to be expanded and extended to meet the needs of NEWIS. Since the interaction of a region's wind resource and its power system is region-specific, narrowing the focus of a wind integration study to just New England allows for more tailoring of the study to suit its unique wind patterns, installed generation, transmission system, and load patterns. As stated by the North American Electric Reliability Corporation (NERC) Integration of Variable Generation Task Force (IVGTF)[42], "The degree to which wind matches demand may differ widely in different geographic areas and at different times of the year. Therefore, it is not possible to generalize the pattern of wind generation across the NERC region."[43] IVGTF further notes that calculating the ELCC of wind power requires careful accounting of the correlation of hourly variable generation and hourly demand, and that "this data is needed for variable generation plants in the specific geographic regions being studied."[44]

In general, the vast footprint of the Eastern Wind Dataset precludes significant consideration of the specific characteristics of the regional wind resource, land use patterns, and power system. For example, in contrast to the expansive wind resources located in the Great Plains, the

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[41] A Markov chain represents a random process where the probability distribution of some future state depends only on the current state. In its application to wind forecasting, the stochastic nature of wind is represented so that the future distribution of future wind speeds (or wind power output) depends only on the current wind speed (or power output).

[42] The IVGTF was created by NERC's Planning and Operating Committees in December 2007 to raise industry awareness/understanding of the characteristics of variable generation and the challenges associated with large-scale integration of variable generation.

[43] IVGTF report, p. 15

[44] IVGTF report, p. 38

majority of onshore wind resources within New England are located in mountainous pockets, resulting in smaller developable sites. Differences such as these render some site selection assumptions used for EWITS less relevant for NEWIS, and also pose the need for a few different land use exclusions. Additionally, the regional tendency towards smaller wind sites in New England presents a need for greater flexibility in site selection for NEWIS. New England's interties with the New York and the Canadian Maritime Provinces, all of which possess significant native potential wind resource, warrant a more granular examination of the external impacts of wind development from these windy neighbors on the regional bulk power system. Ultimately, incorporation of the aforementioned unique regional characteristics into NEWRAM would facilitate the creation of more insightful wind scenarios, thereby helping to identify and evaluate operational issues imposed by significant wind penetrations on New England's bulk power system.

In order to expand the dataset for NEWIS, the New England subset of the more comprehensive 3,000 GW site set was employed rather than those solely from the final 580 GW Eastern Wind Dataset. Again, the larger set was that from which NREL hand selected the final 580 GW dataset primarily by using a list of projects sorted by capacity factor to meet a capacity target for each state. Use of the larger set added 164 more onshore sites, and more than doubled the potential onshore wind resources available for the NEWIS from approximately 14.4 GW to almost 35.6 GW. No offshore sites were eliminated during NREL's final hand selection process, so no additional offshore sites are contained within the larger set. Table 2–2 lists the additional sites included that were added from the larger set to the Eastern Wind Dataset.

Table 2–2 Additional Sites Included in NEWIS Dataset

	Onshore Sites	
State	Count	Total MW
Connecticut	25	3679.2
Maine	107	13623.9
Massachusetts	5	683.6
New Hampshire	5	585.2
Rhode Island	4	478.9
Vermont	18	2134.8
Total	164	21185.3

As a starting point in the development of realistic wind scenarios, it was deemed necessary that the NEWRAM include wind projects already existing in New England, as well as those projects that have initiated the development process as demonstrated by their presence in the ISO-NE Generator Interconnection Queue.[45] It was therefore important that Queue sites be included in the NEWRAM irrespective of exclusions. As of April 17, 2009, 4,169 MW of wind projects were in the Queue, 1,140 MW of which had received a determination of approval based on information reviewed by ISO during the System Impact Study (SIS)/I.3.9 process.[46]

Upon review, it was determined that the Queue sites were either coincident or adjacent and sufficiently close to the sites in the expanded set, and therefore, the expanded set was adequately representative of the regional wind resource. Table 2–3 is a breakdown of wind projects in the Queue that were included in the NEWRAM.

[45] The ISO-NE Generator Interconnection Queue is used to manage generator Interconnection Requests submitted for generators larger than 5 MW in capacity. There are three processes involved in interconnecting a generator: an interconnection process, a market process, and an I.3.9 approval process. Completion of the interconnection process results in an Interconnection Agreement. A generator's satisfaction of the requirements of the market process results in a Market Participant Service Agreement outlining the generator's participation in the Markets for the sale of energy, capacity, and/or ancillary services. Satisfactory completion of the I.3.9 process leads to the ISO granting permission to the generator to operate when interconnected to the regional system.

[46] A SIS is a peer review process to ensure that a generator or transmission project has no significant adverse impact on reliability. A determination of approval under Section I.3.9 of the ISO Tariff is a recommendation that a Queue project will not have significant adverse impact on transmission facilities or the system of another Market Participant.

Table 2–3 Breakdown of wind projects in the ISO-NE Queue as of April 17, 2009

	Onshore Sites		Offshore Sites	
State	**Count**	**Total MW**	**Count**	**Total MW**
ME - SIS/I.3.9 Complete	6	429	0	0
SIS/I.3.9 Pending	22	2252	0	0
MA - SIS/I.3.9 Complete	2	44	1	460
SIS/I.3.9 Pending	1	15	0	0
NH - SIS/I.3.9 Complete	2	136	0	0
SIS/I.3.9 Pending	3	264	0	0
VT - SIS/I.3.9 Complete	2	71	0	0
SIS/I.3.9 Pending	3	138	0	0
RI - SIS/I.3.9 Complete	0	0	0	0
SIS/I.3.9 Pending	0	0	1	360
CT - SIS/I.3.9 Complete	0	0	0	0
SIS/I.3.9 Pending	0	0	0	0
Total	**41**	**3349**	**2**	**820**

2.1.2.1 Additional Exclusions

At the request of the ISO, additional exclusions specifically suited to the NEWRAM were added to the Eastern Wind Dataset screening process. Some, like the buffer around two regional recreation trails, are more restrictive than the Eastern Wind Dataset; others like the lower class wind speed exclusion are more permissive than the Eastern Wind Dataset. The requested exclusions include the following:

Onshore Sites:

- Class 2 or lower wind speed (at 80m)
- Within a buffer of 4 miles for the Appalachian Trail and Long Trail
- Elevations over 3,000 feet – restricting to lower elevations:
    - Reduces blade icing problems
    - Reduces installation costs
    - Reduces impact on viewshed
- Screen out Martha's Vineyard, MA and Nantucket, MA

Offshore Sites:

- Class 4 or lower wind speed (at 80 meters)
- Sites must be at least:
    - o 8 km from mainland for Maine
    - o Outside of state waters for Massachusetts, Rhode Island, and New Hampshire

After incorporating the exclusions, it was determined that there was a pool of potential sites sufficient to begin development of the NEWIS wind scenarios.

2.1.2.2 ***Expanded Validation***

Additional wind speed validation was performed using four measurement stations in New England and four in New York. Based on a review comparing modeled versus measured wind data, no changes to the data resulted from the expanded validation.

Expanded validation of power output data was conducted with respect to nearest of five operational wind plants in New England for which there is 10-minute plant output data. Two of the five operational plants provided data covering the entire 3-year period simulation, and a third plant provided approximately 8 months of coincident data. Two plants provided data more recent than the simulation period. Regardless of the duration of coincident data, a comparison of the diurnal and seasonal trends between measured and simulated data were evaluated. Based on the results of the power validation, the power plant data was left intact and utilized for the final development of the NEWIS wind scenarios.

See Appendix A for AWST's tables and figures associated with the extended wind speed and power output validation.

2.1.2.3 ***Modeling of Wind in Neighboring Systems***

Wind power production within NYISO and PJM was projected to develop in parallel to native wind development. Therefore, wind power's contribution to the total energy demands of both the NYISO and PJM were assumed to match those of wind's contribution in New England. For example, if a regional wind scenario was developed to meet 20% of the New England's total energy demand, the assumed wind penetrations were assumed to meet the same energy requirements in both NYISO and PJM. Wind plant siting and transmission required within these balancing areas was not considered for the NEWIS.

A dataset similar to the Eastern Wind Dataset was developed for the Maritime Canadian Provinces of New Brunswick, Nova Scotia, and Prince Edward Island. Table 2–4 shows a total of 76 potential onshore sites totaling a nameplate capacity of almost 10.4 GW, and a total of 39 offshore sites representing almost 4.8 GW nameplate that were identified. Since the onshore wind resource synthesized for the Maritimes exhibited a high capacity factor, no offshore sites were selected for the Maritimes wind fleet modeled for the NEWIS Maritime scenarios.

Table 2-4 Sites added for Canadian Maritime Provinces

	Onshore Sites		Offshore Sites	
State	Count	Total MW	Count	Total MW
New Brunswick	10	948.1	8	906.6
Prince Edward Island	12	2489.3	9	1195.4
Nova Scotia	54	6931.8	22	2660
Total	76	10369.2	39	4762

In summary, the NEWIS dataset differs from the New England region of the Eastern Wind Dataset in the following ways:

1. The Eastern Wind Dataset model was expanded to cover the Canadian Maritime Provinces of New Brunswick, Prince Edward Island, and Nova Scotia.
2. Additional wind speed and power output validation was performed using data collected from measurement stations and existing wind plants located in New England and New York.
3. AWST provided an expanded dataset (164 additional onshore sites totaling more than 21 GW of nameplate capacity when compared to New England subset of Eastern Wind Dataset) that included existing and proposed wind sites listed on the ISO-NE Generator Interconnection Queue as of April 17, 2009.
4. AWST ensured all Queue sites were scaled commensurate with their proposed installed capacity.
5. Additional exclusions were added to the site selection process.
6. Alterations to site size restrictions were made in order to allow smaller sites.

2.2 Load Data

2.2.1 Source

The ISO develops its plans to address needs in the regional transmission system through an open stakeholder process. Each year these needs are considered over a planning horizon of 10 years as part of the planning process conducted for ISO's Regional System Plan (RSP). Based in part on stakeholder input, the ISO develops plans to meet system needs cost effectively and without degrading the performance of the New England system, the NPCC region, or the remainder of the Eastern Interconnection.[47] In order to aid in the RSP process 13 subsets of the electric power system, called RSP-subareas, have been established to assist in modeling and planning electricity resources. These subareas reflect a simplified model of major transmission bottlenecks of the system, called interfaces, which are physical limitations of the flow of power due to a variety of system conditions (e.g. thermal transfer limit).

The load data used in the hourly production cost simulation analysis portion of the NEWIS comes from the ISO-NE pricing nodes (aka. p-nodes). P-nodes represent locations on the transmission system where generators inject power into the system or where loads withdraw power from the system. Each p-node is related to one or more electrical buses on the power grid.[48] A bus is a specific component of the transmission system at which generators, loads or the transmission system are connected. Therefore the more than 900 p-nodes that are defined electrically are also associated with physical locations within New England.

There is a direct mapping between RSP-subareas and p-nodes such that each p-node exists within one and only one of the 13 RSP-subareas. Similar to p-nodes, RSP-subareas also are associated with physical regions though the true definitions are also based on the electrical network. For the NEWIS, the load data from p-nodes has been aggregated into the respective RSP-subareas.[49] Figure 2–2 is a simplified model of the system that shows a geographical description of the ISO-NE RSP-subareas and three external control areas.

One minute average total ISO New England load data comes from the Plant Information (PI) data historian, which extracts data from the Energy Management System used for power system control.

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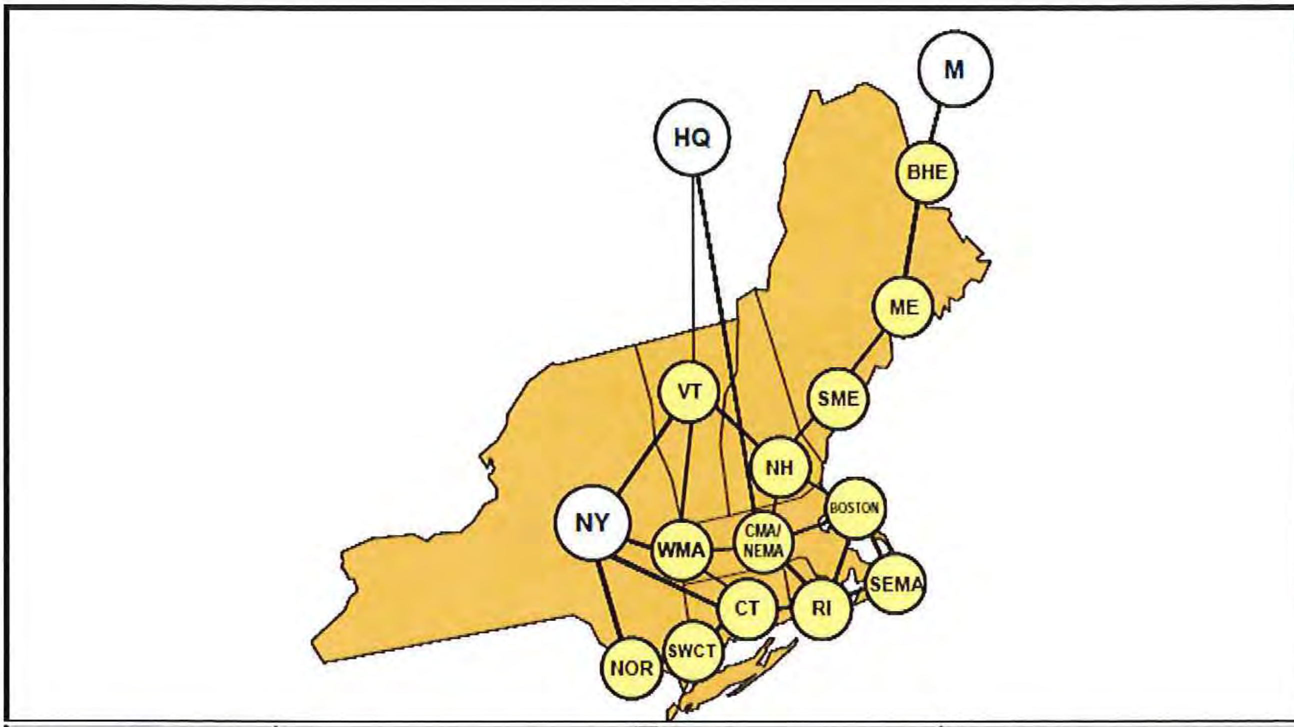
[47] The Eastern Interconnection is the network of interconnected transmission and distribution infrastructure that operates synchronously, and covers the area east of the Rocky Mountains, excluding the portion of the system located in the Electric Reliability Council of Texas (ERCOT) and Quebec.

[48] More information regarding p-nodes can be found in ISO-NE Manual M-11 "ISO New England Manual for Market Operations" available at: http://www.iso-ne.com/rules_proceds/isone_mnls/index.html

[49] A table of the mapping of p-nodes to RSP subareas can be found at, for example http://www.iso-ne.com/stlmnts/stlmnt_mod_info/2006/index.html
P-node tables are updated a few times per year as new generators and loads come into the system.



Subarea Designation	Region or State	Subarea or Control Area Designation	Region or State
BHE	Northeastern Maine	WMA	Western Massachusetts
ME	Western and central Maine/ Saco Valley, New Hampshire	SEMA	Southeastern Massachusetts/ Newport, Rhode Island
SME	Southeastern Maine	RI	Rhode Island/bordering MA
NH	Northern, eastern, and central New Hampshire/eastern Vermont and southwestern Maine	CT	Northern and eastern Connecticut
VT	Vermont/southwestern New Hampshire	SWCT	Southwestern Connecticut
BOSTON	Greater Boston, including the North Shore	NOR	Norwalk/Stamford, Connecticut
CMA/NEMA	Central Massachusetts/ northeastern Massachusetts	M, NY, and HQ	Maritimes, New York, and Hydro-Québec external control areas

Figure 2–2 RSP-subareas Geographical Representation Source RSP06

As mentioned, RSP-subareas are defined by the external and internal interfaces. Figure 2–3 shows a graphical representation of the 13 RSP-subareas and the interfaces between them. Interfaces are used to approximately represent the maximum power flow from one region or RSP-subarea to another. An interface can be one transmission element (transmission line, transformer, etc.) or a group of transmission elements. There are two different characterizations of interfaces: closed and open interfaces. A closed interface forms a cut-set and will cause separation of two regions if the group of transmission elements that forms this interface is removed from service (by, for example, opening the connecting circuit breakers at a transmission line substation). For example, if the ties across the BOSTON Import interface were cut, the RSP-subarea BOSTON would form an electrical island, separate from the rest of the ISO-NE system. In the case of a closed interface the maximum power transfer limits are relatively constant and known. An open interface does not form a cut-set and therefore will not completely separate two portions of the system and the maximum power limits are less constant and more approximate. For instance the North-South interface is an open interface since the ties may still be connected between the VT RSP-subarea and the external NY system which is also connected to the WMA, CT, and NOR RSP-subareas that are connected to the rest of the ISO-NE system. Though they are shown in Figure 2–3, High Voltage Direct Current (HVDC) lines (i.e. HQ to CMA/NEMA Phase II and NY to CT CSC) are not included in the interface definitions since due to their controllability they may be used independently of the underlying AC transmission system.

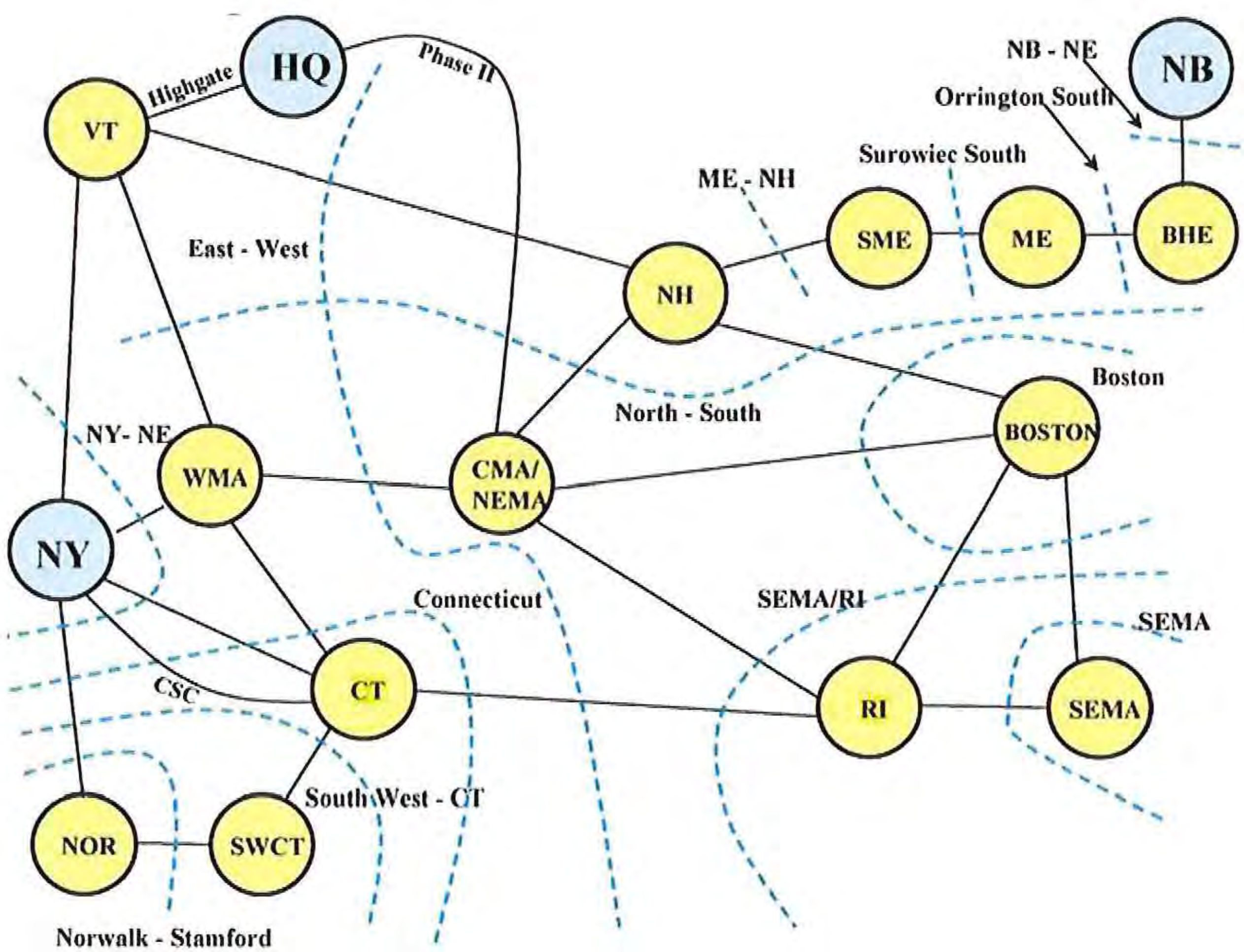


Figure 2–3 RSP-subareas Graphical Representation showing Interfaces Source rsp09

The historical loads for each RSP-subarea for all hours of the years 2004, 2005, and 2006 were time-synchronized with the wind power data synthesized in the mesoscale model development.

In this manner the net load (i.e. load minus wind) could be used for the dispatch of the more conventional (i.e. dispatchable) resources on the system. The net load concept is critical to determining the operating impacts that wind generation may have for two reasons 1) power produced by wind is essentially used as available (i.e. wind is a non-dispatchable resource) and 2) the variability that must be matched by the fleet of dispatchable resources is the combination of the variability introduced by wind and by load which are somewhat correlated. Since the variability of wind and the variability of load are somewhat correlated (i.e. neither perfectly correlated or anti-correlated nor completely uncorrelated) they cannot be analyzed independently.[50]

2.2.2 *Extrapolation Methodology and Effects*

One difficulty in this study has been to determine the best manner in which to extrapolate the 2004 thru 2006 loads out to what they might be during the timeframe under study (i.e. the approximate year of 2020). A complicating factor is that whatever extrapolation methodology employed should preserve the shape of the loads in order to preserve the "net load" concept where the variability on the system is determined by subtracting the time-synchronous wind generation from native load on the system. This net load concept allows for a more complete picture of how the dispatchable resources on the system will be utilized, since the wind generation will essentially be an "as available" resource (due to its low operational cost and policy incentives to maximize wind derived energy) and this as available resource shares some (but not all) of the originating phenomena that drive the load: over most timescales, load and wind are only loosely correlated (at best).

After initial attempts at developing a more complex extrapolation technique, simple peak ratio scaling was selected as the preferred method of extrapolation. In peak ratio scaling, the peak load hour is multiplied by a value to bring it to the expected target peak (in this case 31.5 GW). All other hours in the year are multiplied by this same value. This process was used for each of the years investigated (2004, 2005, and 2006). Table 2–5 shows each year's peak load and the peak load ratio used to multiply all the loads for each year.

[50] A further description of the net load concept and its criticality to determining operational impacts can be found in the report Analysis of Wind Generation Impact on ERCOT Ancillary Services Requirements by GE Energy Applications and Systems Engineering.

Table 2–5 Load Extrapolation using Peak Load Methodology

Year	Peak Load	31.5 GW/Peak Load
2004	23.4 GW	1.344
2005	25.9 GW	1.214
2006	27.2 GW	1.158

All forms of load extrapolation possess certain advantages and disadvantages: though peak load scaling does not allow precise matching for specific energy targets, peak load scaling is straightforward and completely preserves the load shape which also has the effect of growing the hour-to-hour load changes in a predictable and reasonable fashion. Peak scaling ratio is a common method for load extrapolation both in general and for wind integration studies. The main effect of peak load scaling is that the amount of annual energy for the extrapolated load varies somewhat between the years since the load shapes are different for each of the three years. Figure 2–4 shows the unscaled loads above and the scaled loads below.

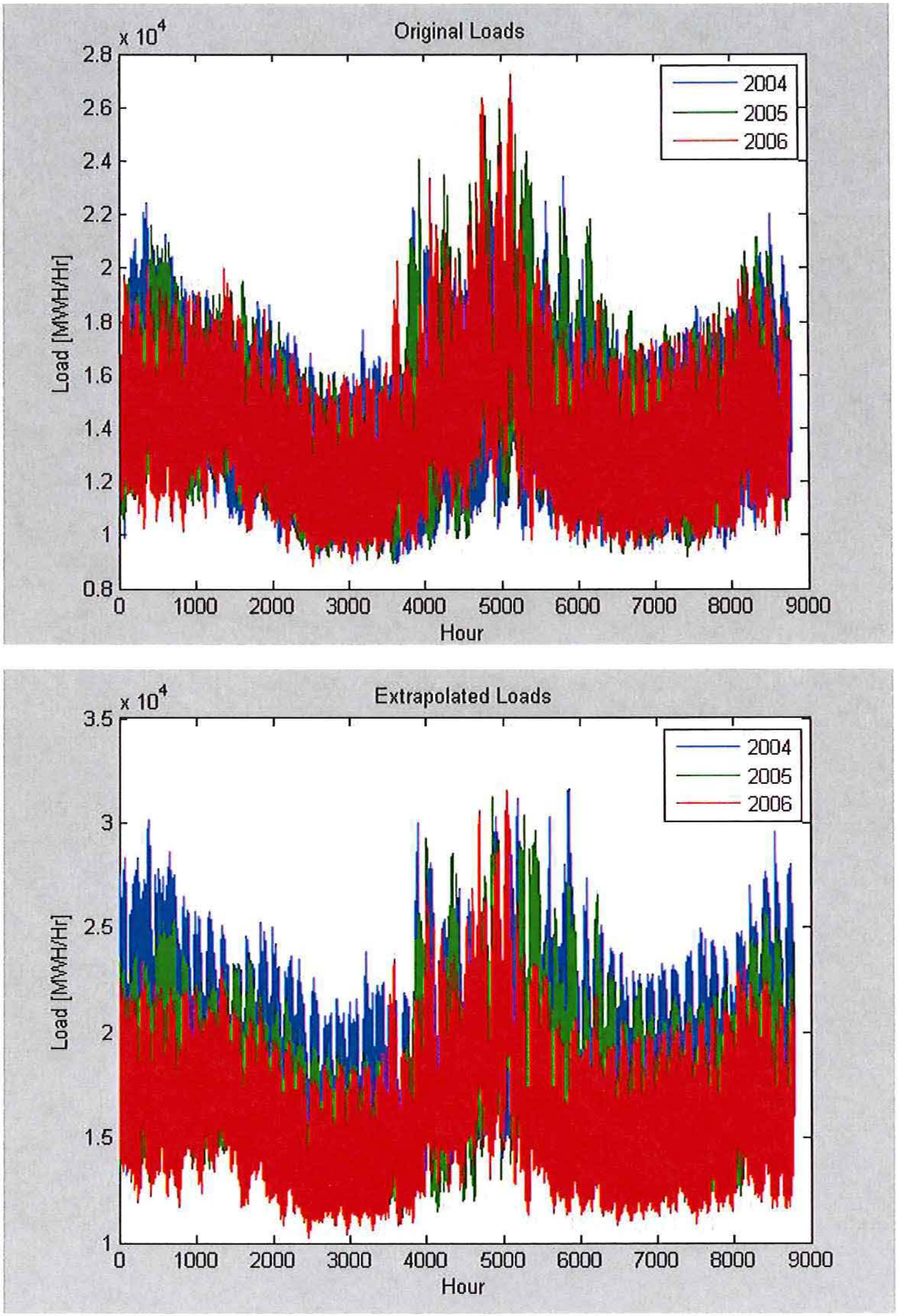


Figure 2–4 Original and Extrapolated Loads

As can be observed in the top half of Figure 2–4, the original load shapes are different from each other. For instance, the peak load hour in 2004 occurs much later in the year (approximately hour 5800) than it does for the peak hours in 2005 and 2006 (both of which occur at about hour 5200). The peak loads for 2005 and 2006 are also much closer in magnitude (25.9 GW and 27.2 GW) as compared to the peak load of 2004 (23.4 GW). Also of note is that there are higher loads in the winter of 2004 than there are in the years of 2005 and 2006. These differences are somewhat magnified by the peak load scaling, as can be seen in the bottom half of Figure 2–4. Also, since the peak load ratio is larger for 2004 than it is for either 2005 or 2006, all loads in 2004 are multiplied by a larger value for extrapolation. This increases the magnitude of the extrapolated loads for the 2004 loadshape and its effect is particularly visible on the loads during the shoulder months. Also, since the loads in the winter of 2004 are larger than the loads in the winter of 2005 or 2006, the extrapolated loads during the winter of 2004 are significantly higher than those of either 2005 or 2006. Some of the global effects of these differences include the facts that there is a larger annual energy associated with the extrapolated 2004 loadshape than for the 2005 or 2006 loadshapes: 174.42 TWH (2004), 160.75 TWH (2005), and 149.24 TWH (2006); and that there are some larger hour-to-hour changes in the loads for the 2004 and 2005 extrapolated loadshapes as compared to the 2006 extrapolated loadshape.

2.3 Overview of Study Scenarios

2.3.1 Introduction

All of the NEWIS wind scenarios are set to represent approximately the 2020 timeframe. In addition to the base case assumptions, there are five main categories of wind build-out scenarios representing successively greater penetrations of wind. The scenarios are categorized either by the aggregate installed nameplate capacity of wind power or the simulated wind fleet's contribution to the region's forecasted annual energy demand. Values used for wind energy generated by each scenario are averages of the three years simulated via mesoscale modeling. Values of annual energy demand for the region and individual states are also averages for the three extrapolated load years used in the simulations and individual load supplied by energy efficiencies that has been bid into the FCM.

These categories of wind build-out scenarios include:

- Partial Queue Build-out
  - Represents 1.14 GW of installed wind capacity
  - Approximately 2.5% of the forecasted annual energy demand
- Full Queue Build-out
  - Represents 4.17 GW of installed wind capacity

  - Approximately 9% of the forecasted annual energy demand
- Medium wind penetration
  - Represents between 6.13 GW and 7.25 GW of installed wind capacity
  - Approximately 14% of the forecasted annual energy demand
- High wind penetration
  - Represents between 8.29 GW and 10.24 GW of installed wind capacity
  - Approximately 20% of the forecasted annual energy demand
- Extra-high wind penetration
  - Represents between 9.7 GW (for offshore) or 12 GW (for onshore) of installed wind capacity
  - Approximately 24% of the forecasted annual energy demand

Of the five categories, the Partial Queue and Full Queue build-outs are comprised of projects that were in the ISO Generator Interconnection Queue as of April 17, 2009, and the queue lists the proposed point of interconnection for each project. All of the build-outs with greater wind penetration consist of wind plants strategically chosen and added to the Full Queue site portfolio, until either the desired aggregate nameplate capacity or the desired energy contribution of the resulting wind fleet was satisfied. A range of wind plant scenarios was developed to represent what the New England system might look like with varying levels of wind penetration, and to represent different spatial patterns of wind development that could occur, including wind development in the Canadian Maritime Provinces. The objective of scenario development was to enable a detailed evaluation of the operational impacts of incremental wind generation variability and uncertainty on New England's bulk electric power system, including the incremental impact contributed by the spatial diversity of wind plants. The NEWIS was not intended to identify real or preferred wind integration scenarios.

In order to represent the impacts of wind portfolio diversity, five layout alternatives were developed for the medium and high wind penetration scenarios, i.e. the 14% energy and 20% energy scenarios. Two of these layout alternatives were also used for the extra-high wind penetration scenario. A description of the five layout alternatives developed for each energy target follows:

1. Best Sites Onshore – This alternative includes the onshore sites with the highest capacity factor needed to satisfy the desired regional energy or installed capacity component provided by wind power. This alternative's wind fleet is comprised

predominantly of wind plants in Maine and therefore it exhibits low geographic diversity.

2. Best Sites Offshore – This alternative includes the offshore sites with the highest capacity factor needed to satisfy the desired regional energy or installed capacity component provided by wind power. This alternative features the highest overall capacity factor of each energy/capacity scenario set, but also a low geographic diversity. However, the steadier offshore wind resource features a higher correlation with load than onshore-based alternatives.

3. Balance Case (aka. Best Sites) – This alternative is a hybrid of the best onshore and offshore sites, and as such exhibits a high geographic diversity, including a good diversity by state. The offshore component of the wind fleet is divided equally between the states of Massachusetts, Rhode Island, and Maine (this is also the only alternative that includes offshore sites located in Maine). Due to a naming convention change during the course of the NEWIS, this layout alternative may be found listed in this report as either the "Balance Case" or the "Best Sites".

4. Best Sites by State – This alternative likely represents the most spatially diverse native wind fleet, and is comprised of wind plants exhibiting the highest capacity factor within each state to meet that state's contribution of the desired energy goal. For example, in the 20% energy scenario, each state's wind fleet was built out in an attempt to meet 20% of the state's projected annual energy demand so that the overall target of 20% of projected annual energy for New England was satisfied. This alternative enables the investigation of the effects of high diversity and wind power development close to New England's load centers. It should be noted that since the Full Queue contained a disproportionately high capacity of wind projects located in Maine, the aggregate energy produced from these plants contributes approximately 58% of this state's forecasted annual energy demand. This meant that the energy contribution of each of the other states was adjusted (percentage-wise) so that the regional wind fleet would produce the overall desired contribution to the forecasted regional energy demand.

5. Best Sites Maritimes – In addition to the Full Queue sites located within New England, this alternative is made up of extra-regional wind plants in the Canadian Maritimes Provinces sufficient to satisfy the desired New England region's wind energy or installed capacity. No considerations were made regarding transmission upgrades required to deliver the hypothetical wind power to New England. Wind resources in the Maritimes exhibit a high geographic diversity and an overall

capacity factor approaching that of New England's offshore resource. Considering the wind plants in the Full Queue, this alternative features the greatest geographic diversity. Also, given the longitudinal distance of the Maritimes from much of New England, the effects of integrating wind in the presence of time zone shifts could be highlighted.

Table 2–6 below is the complete matrix of scenarios developed for the NEWIS analyses.

Table 2–6 Scenarios Evaluated for the NEWIS

Scenario #	Year	Wind Scenario	Transmission Model	Wind Penetration	Wind Type/Location
1	2020	24% Energy_Best Sites Onshore	Copper Sheet (8GW)	12GW	Queue (4GW) + Best Sites (CV + CF) Onshore
2	2020	24% Energy_Best Sites Offshore	Copper Sheet (8GW)	9.9GW	Queue (4GW) + Best Sites (CV + CF) Offshore
3	2020	24% Energy_Best Sites Onshore	8GW Trans. Overlay	12GW	Queue (4GW) + Best Sites (CV + CF) Onshore
4	2020	24% Energy_Best Sites Offshore	8GW Trans. Overlay	9.9GW	Queue (4GW) + Best Sites (CV + CF) Offshore
5	2020	20% Energy_Best Sites Onshore	Copper Sheet (4GW)	9.8GW	Queue (4GW) + Best Sites (CV + CF) Onshore
6	2020	20% Energy_Best Sites Offshore	Copper Sheet (4GW)	8.3GW	Queue (4GW) + remainder Offshore (CV + CF)
7	2020	20% Energy_Best Sites Maritimes	Copper Sheet (4GW)	9GW	Queue (4GW) + Best Sites Maritimes
8	2020	20% Energy_ Balance Case	Copper Sheet (4GW)	8.8GW	Queue (4GW) + Best Sites (CV + CF) Offshore
9	2020	20% Energy_Best Sites by State	Copper Sheet (4GW)	10.2GW	Queue (4GW) + Best Sites (CV + CF) by State
10	2020	20% Energy_Best Sites Onshore	4GW Trans. Overlay	9.8GW	Queue (4GW) + Best Sites (CV + CF) Onshore
11	2020	20% Energy_Best Sites Offshore	4GW Trans. Overlay	8.3GW	Queue (4GW) + remainder Offshore (CV + CF)
12	2020	20% Energy_Best Sites Maritimes	4GW Trans. Overlay	9GW	Queue (4GW) + Best Sites Maritimes
13	2020	20% Energy_ Balance Case	4GW Trans. Overlay	8.8GW	Queue (4GW) + Best Sites (CV + CF) Offshore
14	2020	20% Energy_Best Sites by State	4GW Trans. Overlay	10.2GW	Queue (4GW) + Best Sites (CV + CF) by State
15	2020	14% Energy_Best Sites Onshore	Copper Sheet (2GW)	6.8GW	Queue (4GW) + Best Sites (CV + CF) Onshore
16	2020	14% Energy_Best Sites Offshore	Copper Sheet (2GW)	6.1GW	Queue (4GW) + remainder Offshore (CV + CF)
17	2020	14% Energy_Best Sites Maritimes	Copper Sheet (2GW)	6.4GW	Queue (4GW) + Best Sites Maritimes
18	2020	14% Energy_ Balance Case	Copper Sheet (2GW)	6.3GW	Queue (4GW) + Best Sites (CV + CF) Offshore
19	2020	14% Energy_Best Sites by State	Copper Sheet (2GW)	7.3GW	Queue (4GW) + Best Sites (CV + CF) by State
20	2020	14% Energy_Best Sites Onshore	2GW Trans. Overlay	6.8GW	Queue (4GW) + Best Sites (CV + CF) Onshore
21	2020	14% Energy_Best Sites Offshore	2GW Trans. Overlay	6.1GW	Queue (4GW) + remainder Offshore (CV + CF)
22	2020	14% Energy_Best Sites Maritimes	2GW Trans. Overlay	6.4GW	Queue (4GW) + Best Sites Maritimes
23	2020	14% Energy_Balance Case	2GW Trans. Overlay	6.3GW	Queue (4GW) + Best Sites (CV + CF) Offshore
24	2020	14% Energy_Best Sites by State	2GW Trans. Overlay	7.3GW	Queue (4GW) + Best Sites (CV + CF) by State
25	2020	9% Energy_Queue	Copper Sheet (2GW)	4.2GW	Queue (4GW)
26	2020	9% Energy_Queue	2GW Trans. Overlay	4.2GW	Queue (4GW)
27	2020	2.5% Energy_Commercial_SIS_1.3.9	Copper Sheet (2019 NPCC)	1.1GW	SIS & I39 Queue
28	2020	2.5% Energy_Commercial_SIS_1.3.9	2019 NPCC Case	1.1GW	SIS & I39 Queue

The lower penetration scenario types were used as building blocks in the development of higher penetration counterpart, e.g. the partial queue is a subset of the full queue, the full queue is a subset of all higher penetration scenarios, the 14% best onshore case is a subset of the 20% best onshore scenario, which in turn is a subset of the 12 GW best onshore scenario. Again, the Full Queue sites (totaling 4.17 GW in installed nameplate capacity) are a subset of each of the medium and higher penetration scenarios, and because these scenarios all have the Full Queue sites in common, the effects of varying spatial diversities of the different wind fleets should be more noticeable as the overall wind penetration increases. It was decided early in the project that due to time and scope constraints that the overlays developed for the Governors' study would be used in the NEWIS. For more information regarding the overlays see section 2.3.9.3.

Upon developing the scenarios and running copper sheet[51] analyses, it was found that the selected wind fleets exhibited higher than expected capacity factors, and that energy targets could be met with a reduced fleet of wind power plants.

2.3.2 ***Base Case – The System without Wind***

The base case scenario is the New England bulk power system without wind power. Therefore, the base case assumptions are common to all the wind build-out scenarios. Since the historic years used to simulate system load for NEWIS date back to when there was only a negligible amount of wind power installed on the system, the base case was used to calibrate the system model.

Without wind, many of the assumptions made about the balance of the bulk regional power system are similar to those in the Governor's Study. For all the wind scenarios, system load characteristics include a regional forecasted 50/50 hourly summer peak load[52] assumed to be 31,500 MW, and a regional Installed Capacity Requirement (ICR)[53] of 35,100 MW. This forecasted ICR is a measure of the installed resources that are projected to be necessary to meet reliability standards in light of total forecasted load requirements for New England and to maintain sufficient reserve capacity to meet reliability standards, which are defined for the New England Balancing Authority Area of disconnecting non-interruptible customers (a Loss of Load Expectation or "LOLE") no more than once every ten years (an LOLE of 0.1 days per year). [54]

The base case represents many assumptions concerning the supply-side portfolio of the bulk power system. Just as has historically been the case, the power system before wind is comprised almost exclusively of a fleet of conventional generation, which was expanded to meet the aforementioned future capacity requirement. Figures 2-5 and 2-6 show the capacity and energy,

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[51] In a "copper sheet" analysis limitations on the flow of electrical power are governed only by the network impedances: transfer limits (whether thermal, voltage, or stability) are removed in order to determine the nature of the underlying flow of power. This analysis is useful in determining where increasing transfer capability would be especially useful by reducing or eliminating congestion

[52] The term 50/50 hourly peak load refers to a forecast scenario in which there is a 50 percent chance that the actual hourly loads will be greater than the forecasted load, and a 50 percent chance that the forecasted hourly loads will be.

[53] Installed Capacity Requirement (ICR) is the amount of installed resources (capacity) needed to meet ISO-NE's Resource Adequacy Criterion. In this case, it is the ICR to meet the estimated 50/50 hourly peak load for the simulation timeframe.

[54] For more on ICR see: http://www.iso-ne.com/genrtion_resrcs/reports/nepool_oc_review/2009/index.html

respectively, of the generation in the New England System. In order to realistically model the base case, conventional generators added beyond those already existing on the system are those that have participated in the 2012/2013 Forward Capacity Auction, and have submitted interconnection requests within the ISO Generation Queue. Almost all of the conventional generation added is natural gas-fired thermal units.[55] Base fuel prices are those predicted by the Energy Information Agency (EIA) for the year 2020.

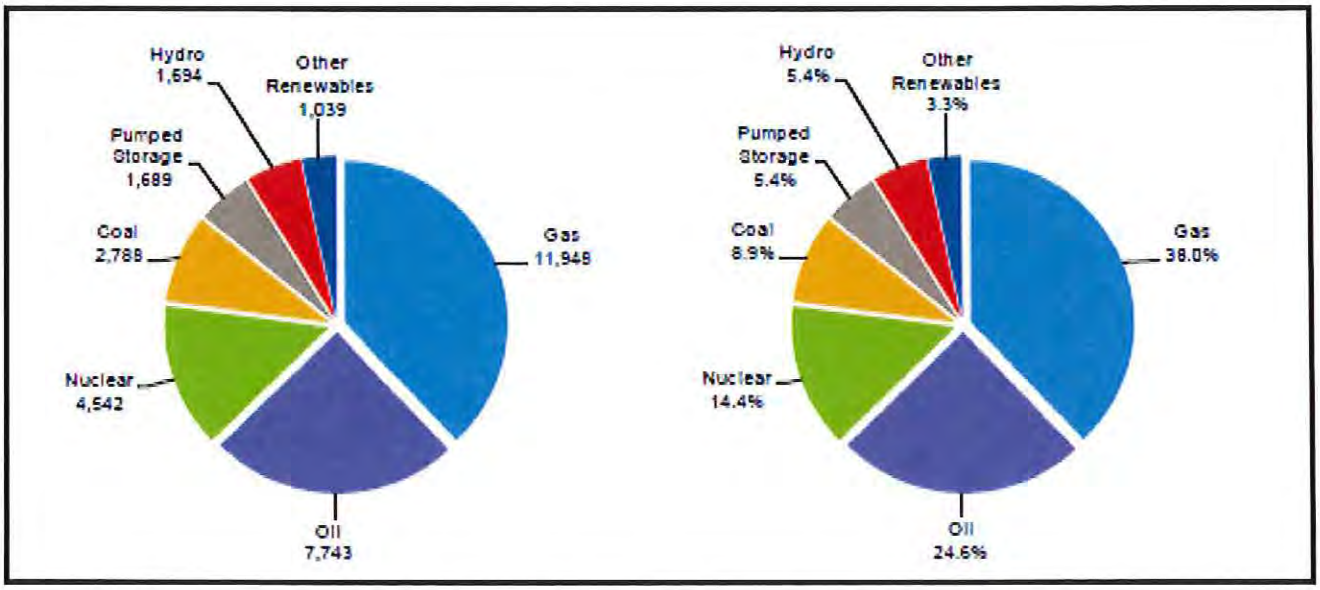

Figure 2–5 Generation capacity mix by primary fuel type, 2009 summer ratings (MW and %).

Note: The "Other Renewables" category includes LFG, other biomass gas, refuse (municipal solid waste), wood and wood-waste solids, wind, and tire-derived fuels. [2009 RSP, p. 61].

[55] FCA 2012/2013 cleared capacity includes 1008 MW of natural gas, 38 MW of landfill gas, 32 MW of biomass and wood/ wood waste, and 78 MW of wind generation

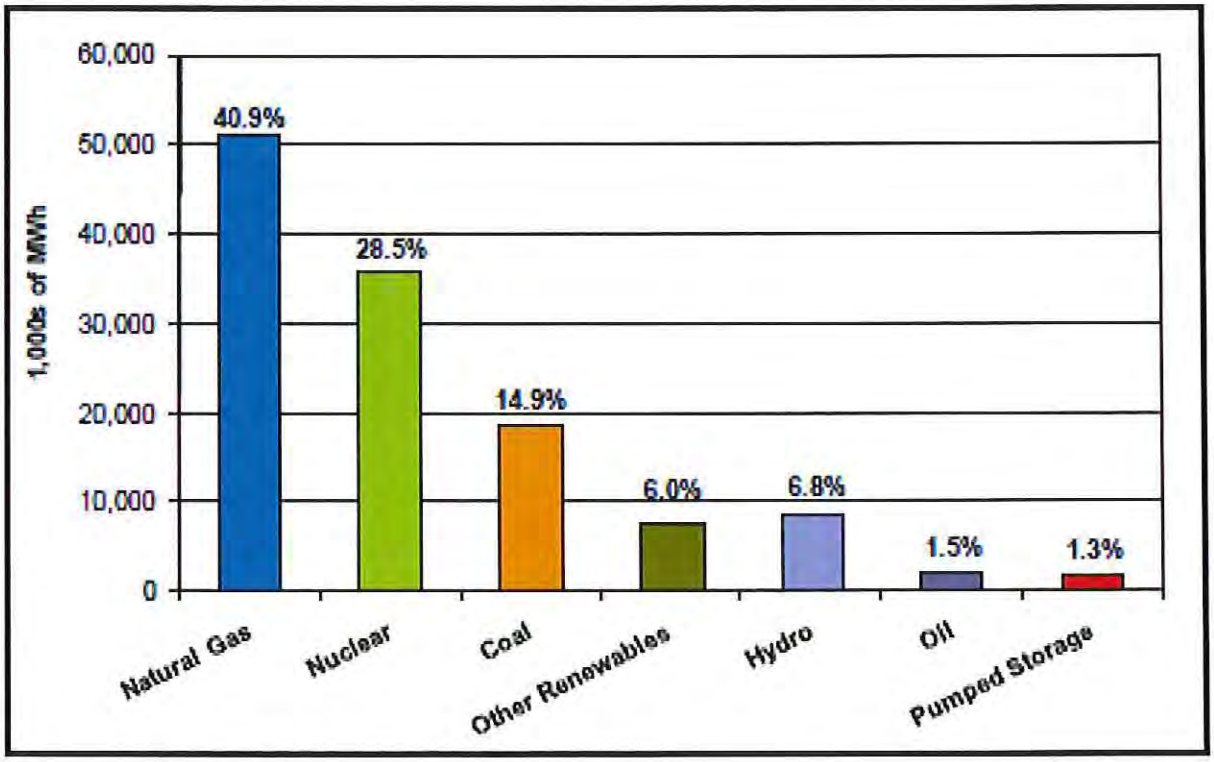

Figure 2–6 **New England electric energy production by fuel type in 2008.**

2.3.3 ***Partial Queue Build-Out***

The partial queue represents a total of 1.14 GW of installed wind capacity, or approximately 2.5% of total annual energy demand forecasted for the New England region. Wind projects included are those either already in service, or are in the April 2009 Generation Queue that have obtained SIS/I.3.9 approval or have an SIS in progress. Therefore, this scenario is the nearest-term wind scenario, representing a regional pattern of wind development that may occur within the first few years of the NEWIS forecast horizon. The Partial Queue scenario is a subset of the Full Queue scenario.

Figure 2–7 depicts the approximate locations of wind projects included in the Partial Queue scenario. The magnitude of installed nameplate capacity corresponding to each site is represented by the size of the circle identifying it: the circles are not to-scale nor are they meant to be to-scale with the underlying figures. As Figure 2–7 illustrates, almost 80% of wind in the partial Queue scenario is located in Maine or off the coast of Massachusetts. The largest project in this scenario, a 460 MW offshore windplant, is visible in the figure as a blue dot located in Nantucket Sound off the coast of Massachusetts in the lower right-hand corner of the figure. A constant legend will be used in all following wind scenario layout figures in order to help the reader differentiate between sites in the different scenarios. This scenario adds no new transmission beyond the basecase 2019 ISO-NE Multi-regional Modeling Working Group (MMWG) library model. As mentioned previously, for more information about the transmission system assumptions please see section 2.3.9.3.

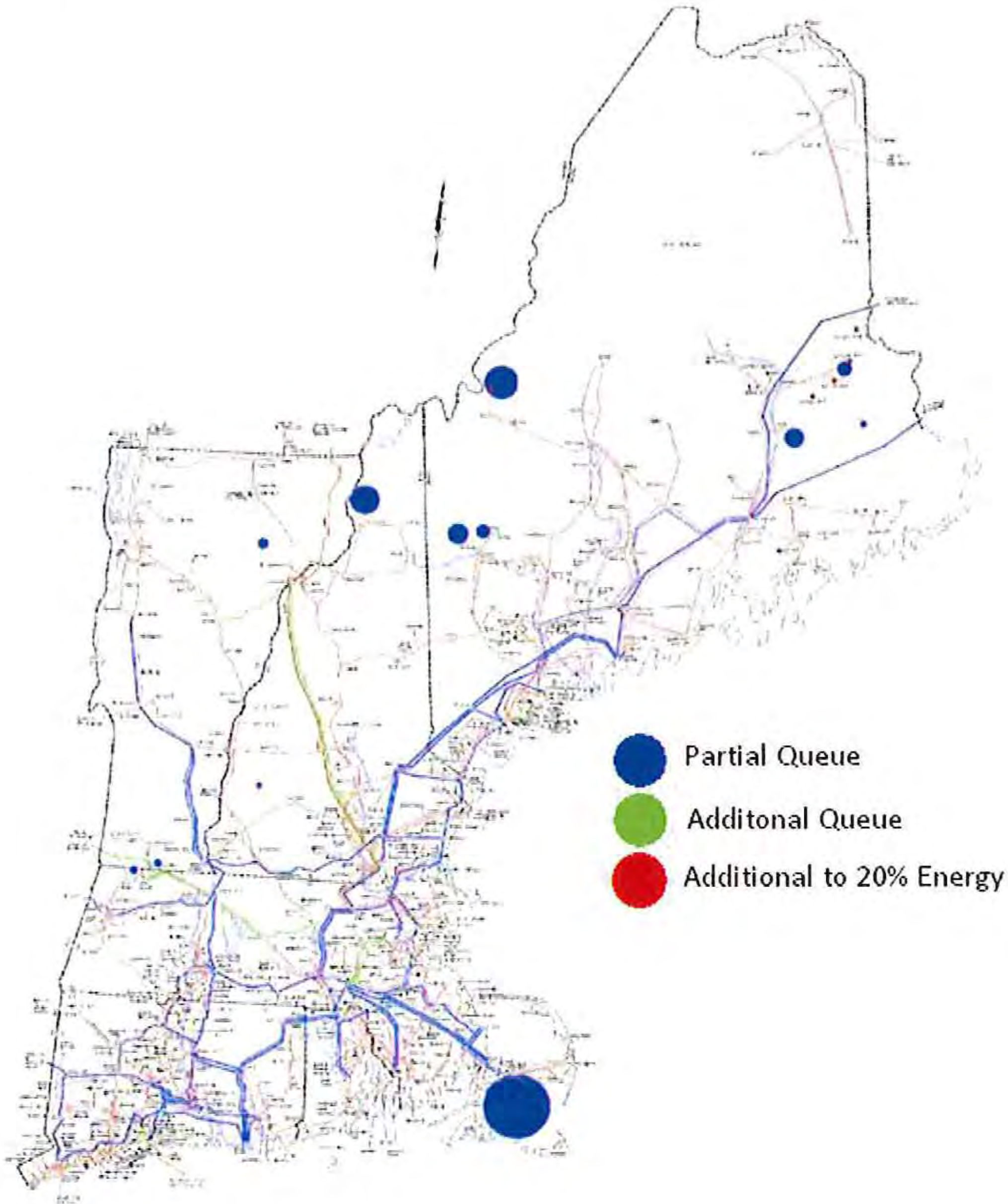

Figure 2–7 Locations of Partial Queue wind sites

Table 2–7 Partial Queue site breakdown

State	Onshore			Offshore			Total			Capacity Factor (%)		
	Site Count	Name Plate (GW)	Energy (GWh)	Site Count	Name Plate (GW)	Energy (GWh)	Site Count	Name Plate (GW)	Total Energy (GWh)	Onshore	Offshore	Total
Connecticut	-	-	-	-	-	-	-	-	-	0%	0%	-
Maine	6	0.429	1,298	-	-	-	6	0.429	1,298	35%	0%	35%
Massachusetts	2	0.044	135	1	0.460	1,615	3	0.504	1,750	35%	40%	40%
New Hampshire	2	0.136	448	-	-	-	2	0.136	448	38%	0%	38%
Rhode Island	-	-	-	-	-	-	-	-	-	0%	0%	-
Vermont	2	0.071	198	-	-	-	2	0.071	198	32%	0%	32%
Total	12	0.680	2,080	1	0.460	1,615	13	1.140	3,695	35%	40%	37%

Table 2–7 is the Partial Queue site breakdown by state, type of wind plant (onshore versus offshore), capacity factor, total nameplate capacity and total energy contribution. Capacity factor and energy values are based on the three-year average energy outputs of each simulated wind plant. For example, Maine's onshore contribution consists of six sites totaling 429 MW in nameplate capacity, an average annual energy output of 1,298 GWh, and an average capacity factor of 35%.

2.3.4 *Full Queue*

The Full Queue represents a total of 4.17 GW of installed wind capacity, or approximately 9% of total annual energy demand for the New England region. Wind projects included are all of those in the Partial Queue, plus the remainder of wind sites in the Generation Queue regardless of SIS/I.3.9 status.[56] This scenario assumes the Governors' 2 GW Overlay for transmission is necessary in order to integrate the sites in Northern Maine.

[56] Wind projects listed as "Withdrawn" within the April 2009 Queue were not included in the full Queue build-out scenario. These sites were excluded since the reason for their withdrawal is unknown and may have included poor siting, e.g. location in an unfavorable wind regime.

Figure 2–8 is an illustration of sites included in the Full Queue. The additional sites, depicted in green, were not part of the Partial Queue scenario. As can be seen in Figure 2–8, sites added are predominantly located in Aroostook County, Maine, with one 360 MW offshore wind plant off the coast of Rhode Island. An important item of note is in order to facilitate this expansion, the assumption was made that transmission would be expanded into the northern portions of Maine (now interconnected via the New Brunswick system) using the Governors' 2 GW overlay.

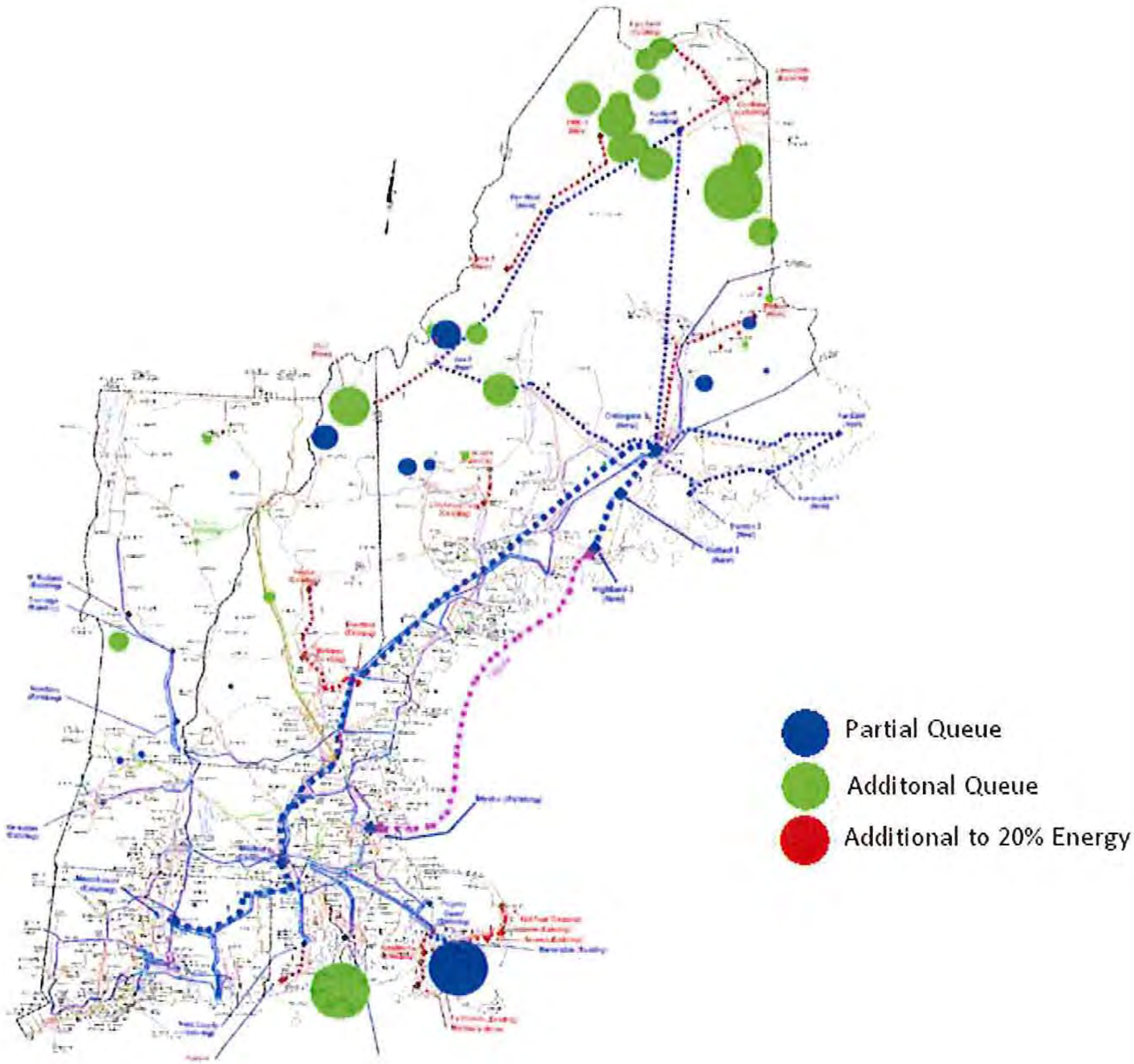

Figure 2–8 **Full Queue wind site locations.**

Table 2–8 Full Queue site breakdown

	Onshore			Offshore			Total			Capacity Factor (%)		
State	Site Count	Name Plate (GW)	Energy (GWh)	Site Count	Name Plate (GW)	Energy (GWh)	Site Count	Name Plate (GW)	Total Energy (GWh)	Onshore	Offshore	Total
Connecticut	-	-	-	-	0.000	-	-	-	-	0%	0%	0%
Maine	28	2.681	7,486	-	0.000	-	28	2.681	7,486	32%	0%	32%
Massachusetts	3	0.059	183	1	0.460	1,615	4	0.519	1,798	35%	40%	40%
New Hampshire	5	0.400	1,290	-	0.000	-	5	0.400	1,290	37%	0%	37%
Rhode Island	-	-	-	1	0.360	1,295	1	0.360	1,295	0%	41%	41%
Vermont	5	0.209	584	-	0.000	-	5	0.209	584	32%	0%	32%
Total	41	3.349	9,543	2	0.820	2,910	43	4.169	12,453	33%	41%	34%

Table 2–8 is the Full Queue site breakdown. A total of 28 onshore sites in Maine are in the Full Queue, with an aggregate nameplate capacity of 2,681 MW, and an average annual output of 7,486 GWh and corresponding 32% capacity factor. One 360 MW offshore wind plant was added in Rhode Island. Note that the Full Queue scenario is a subset of all of the build-out scenarios featuring greater wind penetrations.

2.3.5 High Penetration Scenarios - 20% Energy

The purpose of the 20% energy target of the high penetration scenarios is to reflect the approximate effects of each state attempting to meet its RPS target using wind power. Additionally, there is ongoing discussion as to how large wind penetrations can be before alternative modes of study may be required[57]. Common thought is that this is somewhere in the range of 20% to 30% energy penetration, and so the NEWIS pushes this boundary while obtaining results that are relevant and well founded. All NEWIS 20% energy penetration scenarios use the Governors' 4 GW Overlay. In some cases (e.g. the Best by State Scenario, or the Best Offshore Scenario) portions of the overlay would be "overdesigned" and power flows on these portions would not reach the developed transfer limits.

[57] For example, incorporation of probabilistic planning techniques. see the NERC IVGTF report: http://www.nerc.com/files/IVGTF_Report_041609.pdf

2.3.5.1 *Best Onshore + Full Queue – 20% Energy*

The 20% Energy Full Queue plus Best Onshore scenario represents a total of 9.78 GW of installed wind capacity. Wind projects included are those in the Full Queue, plus the onshore sites within the NEWRAM with the highest capacity factor to meet the 20% regional energy target. Figure 2–9 illustrates the sites in this layout. Sites in red are not part of the Full Queue scenario. As can be seen in Figure 2–9, sites added are predominantly located in northern Maine, with several sites located in Vermont and New Hampshire. Due to lower capacity factors, only two additional sites are located in Massachusetts, no new sites are located in Rhode Island, and Connecticut remains without a wind project.

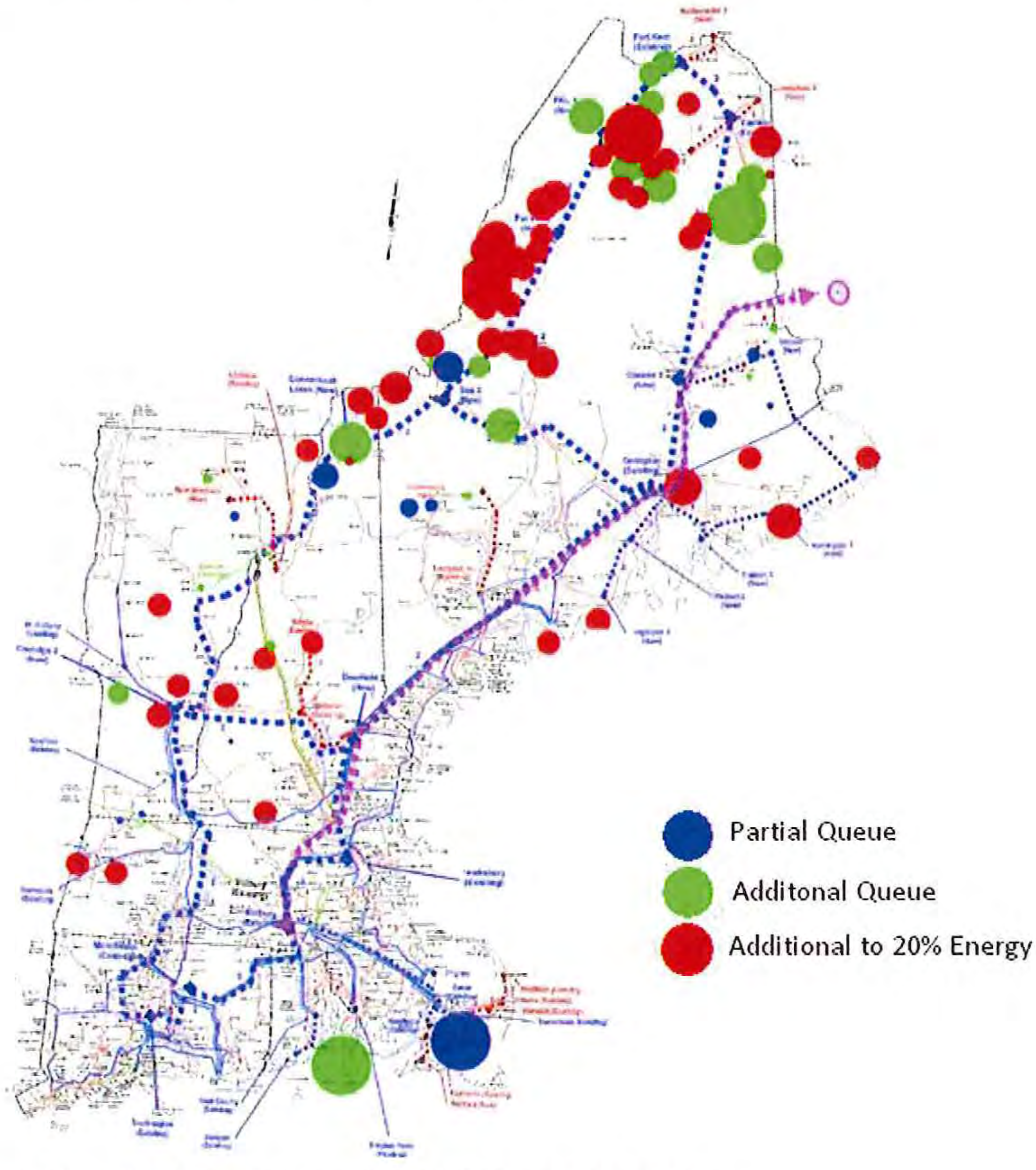

Figure 2–9 20% Energy Full Queue plus Best Onshore wind site locations

Table 2–9 20% Energy Full Queue plus Best Onshore site breakdown

State	% Energy by State	Onshore			Offshore			Total			Capacity Factor (%)		
		Site Count	Name Plate (GW)	Energy (GWh)	Site Count	Name Plate (GW)	Energy (GWh)	Site Count	Name Plate (GW)	Total Energy (GWh)	Onshore	Offshore	Total
Connecticut	0%	-	-	-	-	-	-	-	-	-	0%	0%	0%
Maine	157%	63	7.001	20,226	-	-	-	63	7.001	20,226	33%	0%	33%
Massachusetts	4%	5	0.259	744	1	0.460	1,615	6	0.719	2,359	33%	40%	37%
New Hampshire	30%	12	1.064	3,335	-	-	-	12	1.064	3,335	36%	0%	36%
Rhode Island	10%	-	-	-	1	0.360	1,295	1	0.360	1,295	0%	41%	41%
Vermont	23%	11	0.635	1,845	-	-	-	11	0.635	1,845	33%	0%	33%
Total	20%	91	8.959	26,150	2	0.820	2,910	93	9.779	29,060	33%	41%	34%

Table 2–9 is the 20% Energy Full Queue plus Best Onshore site breakdown. A total of 63 onshore sites are now located in Maine (35 of which are added to the full queue), with an aggregate nameplate capacity of 7,001 MW, and an average annual output of 20,226 GWh and corresponding 33% capacity factor. Maine wind plants therefore account for almost 70% of the total wind energy generated in this scenario, which is more than one-and-a-half times the state's annual energy demand. This scenario exhibits an overall 34% average capacity factor, which is lower than all but one of the other 20% energy scenarios, due to its emphasis on onshore wind development, which generally has a lower capacity factor than offshore wind power. Additionally, this scenario features a total of 91 wind plants, the most of the 20% scenarios.

2.3.5.2 Best Offshore + Full Queue – 20% Energy

The 20% Energy Full Queue plus Best Offshore scenario represents a total of 8.29 GW of installed wind capacity. Wind projects included are all of those in the Full Queue, plus the offshore sites within the NEWRAM with the highest capacity factor that meet the 20% regional energy target.

Figure 2–10 is an illustration of sites included in the 20% Energy Full Queue plus Best Offshore scenario. Depicted in red are those sites not included in the Full Queue scenario. As can be seen in Figure 2–10 and Table 2–10, only four offshore wind plants (depicted in red in Figure 2–10) totaling 4,125 MW in nameplate capacity off the coast of Massachusetts are added to the Full Queue.

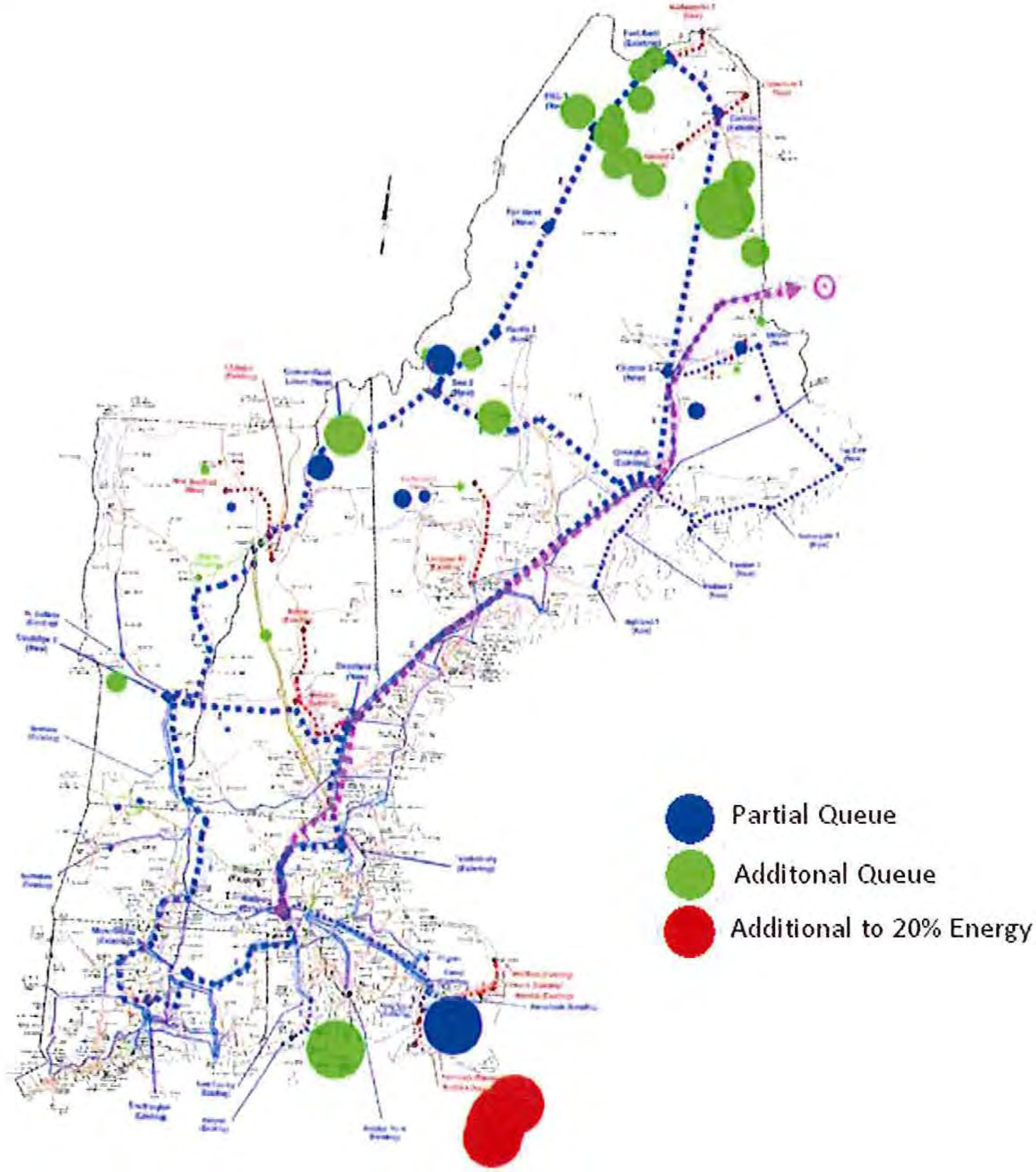

Figure 2–10 20% Energy Full Queue plus Best Offshore wind site locations

Table 2–10 20% Energy Full Queue plus Best Offshore site breakdown

State	% Energy by State	Onshore			Offshore			Total			Capacity Factor (%)		
		Site Count	Name Plate (GW)	Energy (GWh)	Site Count	Name Plate (GW)	Energy (GWh)	Site Count	Name Plate (GW)	Total Energy (GWh)	Onshore	Offshore	Total
Connecticut	0%	-	-	-	-	-	-	-	-	-	0%	0%	0%
Maine	58%	28	2.681	7,486	-	-	-	28	2.681	7,486	32%	0%	32%
Massachusetts	28%	3	0.059	183	5	4.585	18,222	8	4.644	18,405	35%	45%	45%
New Hampshire	12%	5	0.400	1,290	-	-	-	5	0.400	1,290	37%	0%	37%
Rhode Island	10%	-	-	-	1	0.360	1,295	1	0.360	1,295	0%	41%	41%
Vermont	7%	5	0.209	584	-	-	-	5	0.209	584	32%	0%	32%
Total	20%	41	3.349	9,543	6	4.945	19,517	47	8.294	29,060	33%	45%	40%

Table 2–10 is the 20% Energy Full Queue plus Best Offshore site breakdown. The overall average capacity of the scenario is 40%, highest of the 20% scenarios. The five offshore wind plants in Massachusetts account for 55% of the nameplate capacity and almost 63% of the energy output region's wind fleet. Compared to the regional onshore wind resource, the offshore wind resource is greater and features much less spatial variation (i.e. it is more consistent both temporally and spatially), which gives the offshore scenarios the highest capacity factors of all the study scenarios.

2.3.5.3 ***Balance Case[58] – 20 % Energy***

The 20% Full Queue plus Balance Case represents a total of 8.80 GW of installed wind capacity. Wind projects included are all of those in the Full Queue, plus the addition of 3.7 GW of offshore wind, and lastly the addition of onshore sites with the highest capacity factor required to meet the 20% total energy target. The offshore wind plants are divided evenly between the states of Maine, Massachusetts, and Rhode Island, each containing 1.5 GW of offshore wind nameplate capacity.

[58] Due to a naming convention change during the course of the NEWIS, this layout alternative can be found in this report listed as either the "Balance Case" or the "Best Sites"

Figure 2–11 is an illustration of sites included in the 20% Full Queue plus Balance Case. As can be seen, very few onshore sites have been added to the Full Queue portfolio, and there is a diverse distribution of wind plants across the region, including a fairly even distribution of offshore sites. Again, no wind projects are located in Connecticut due to its relatively poor wind resource, both onshore and offshore.

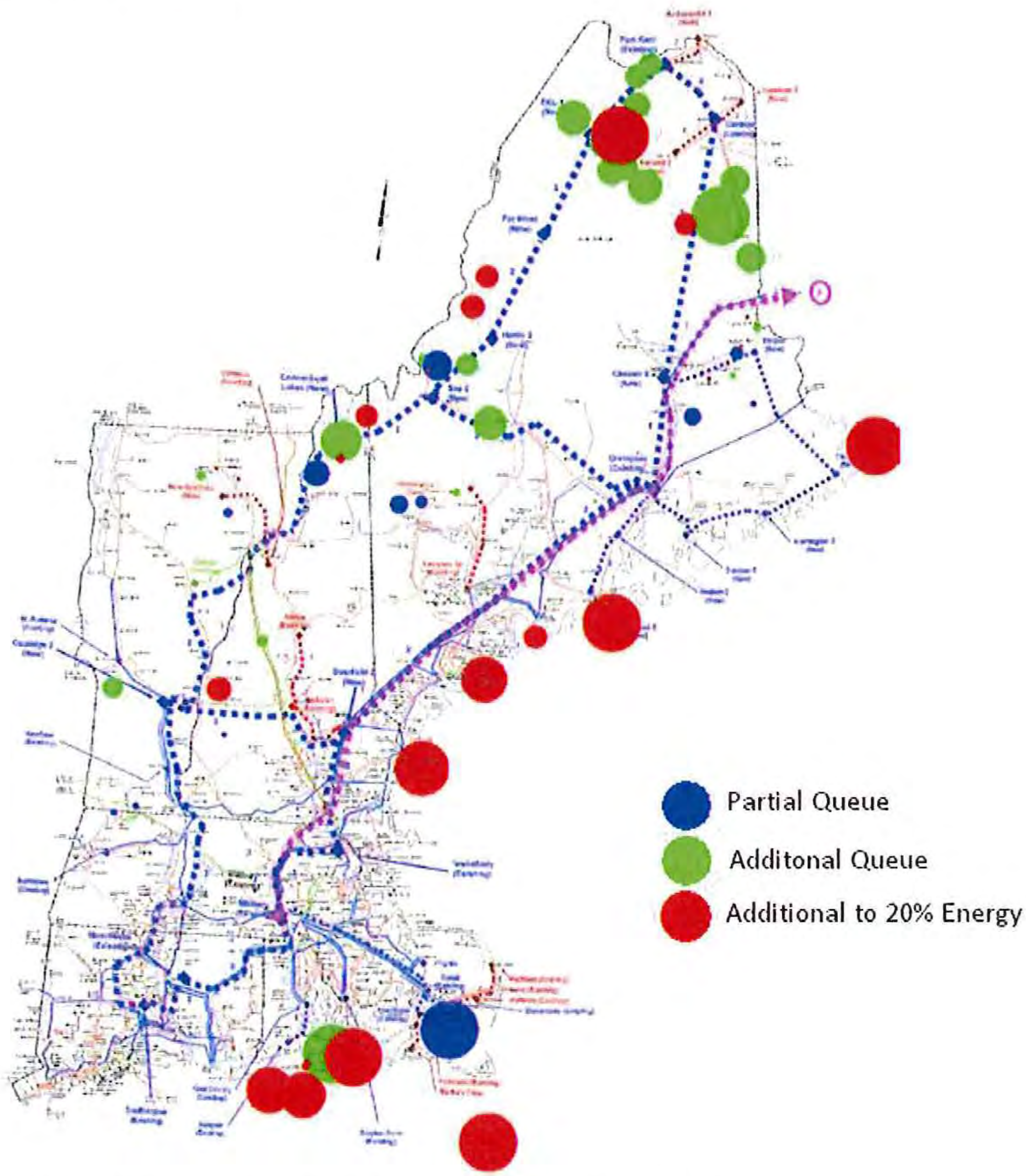

Figure 2–11 20% Energy Full Queue plus Balance Case wind site locations

Table 2–11 20% Energy Full Queue plus Balance Case site breakdown

State	% Energy by State	Onshore Site Count	Onshore Name Plate (GW)	Onshore Energy (GWh)	Offshore Site Count	Offshore Name Plate (GW)	Offshore Energy (GWh)	Total Site Count	Total Name Plate (GW)	Total Energy (GWh)	Capacity Factor (%) Onshore	Capacity Factor (%) Offshore	Capacity Factor (%) Total
Connecticut	0%	-	-	-	-	-	-	-	-	-	0%	0%	0%
Maine	114%	33	3.372	9,571	4	1.500	5,169	37	4.872	14,740	32%	39%	35%
Massachusetts	9%	3	0.059	183	2	1.498	5,800	5	1.557	5,982	35%	44%	44%
New Hampshire	19%	8	0.647	2,096	-	-	-	8	0.647	2,096	37%	0%	37%
Rhode Island	44%	-	-	-	7	1.513	5,657	7	1.513	5,657	0%	43%	43%
Vermont	7%	5	0.209	584	-	-	-	5	0.209	584	32%	0%	32%
Total	20%	49	4.287	12,435	13	4.511	16,625	62	8.798	29,060	33%	42%	38%

Table 2–11 is the 20% Full Queue plus Balance Case site breakdown. Non-Queue sites selected for this 20% scenario include a total of 8 onshore wind plants with an aggregate nameplate capacity of 938 MW, and 11 offshore sites totaling 3,691 MW. Due to the large component of offshore wind (there is almost an even split between offshore and onshore total wind capacity) this scenario has a 38% capacity factor, second highest of the 20% scenarios. A total of 37 wind plants (33 onshore, 4 offshore) are sited in Maine, with an aggregate nameplate capacity of 4,872 MW, and a total average annual output of 14,740 GWh, or half of the total wind energy generated in this scenario.

2.3.5.4 Best By State + Full Queue – 20% Energy

The 20% Energy Full Queue plus Best By State scenario represents a total of 10.24 GW of installed wind capacity. Wind projects included are all of those in the Full Queue, plus the addition of both onshore and offshore sites within each state to attempt to meet approximately 20% of each state's energy demand. Due to the disproportionate amount of Maine wind plants in the Queue, it had already met 58% of its own average annual energy demand without any additions. This meant that in order to meet the 20% regional target, the state energy targets of additional wind plants sited in other states had to be lowered commensurately, i.e. wind plants sited in Connecticut, Massachusetts and Rhode Island generate 16% of their respective annual state energy demands.

Figure 2–12 is an illustration of sites included in the 20% Energy Full Queue plus Best By State scenario, and depicts a high diversity of onshore wind, and a strong correlation between wind plant scenario layout and load centers, especially in southern New England. Due to lower capacity factors and higher loads within the states, many onshore sites are located in Massachusetts and Connecticut. For Massachusetts, it was decided that a fleet of mostly onshore sites in the state would possibly enable the study of different operational effects versus the 20% Best Offshore scenario due to the enhanced diversity of onshore fleet.

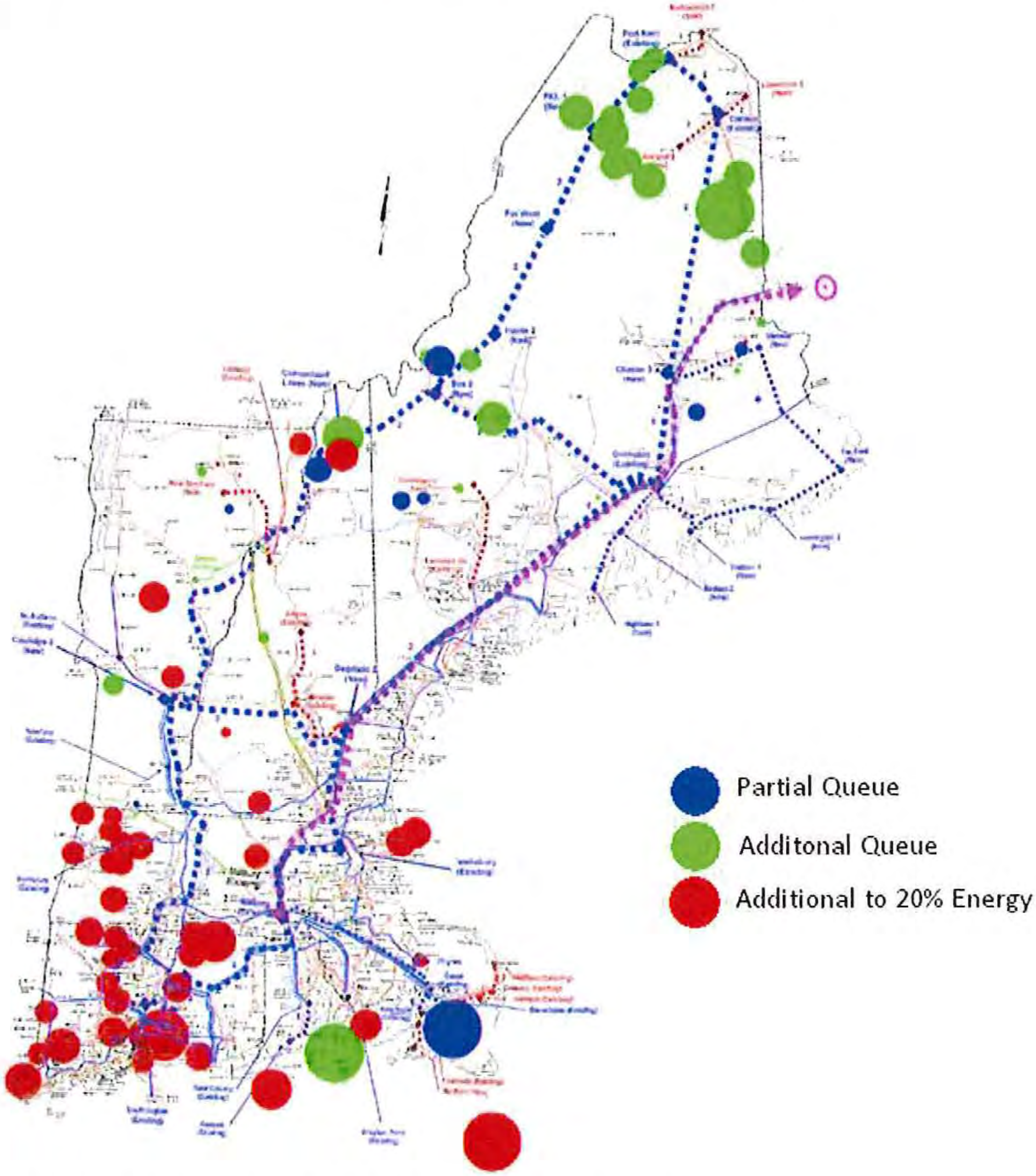

Figure 2–12 20% Energy Full Queue plus Best By State wind site locations

Table 2–12 20% Energy Full Queue plus Best By State site breakdown

State	% Energy by State	Onshore			Offshore			Total			Capacity Factor (%)		
		Site Count	Name Plate (GW)	Energy (GWh)	Site Count	Name Plate (GW)	Energy (GWh)	Site Count	Name Plate (GW)	Total Energy (GWh)	Onshore	Offshore	Total
Connecticut	16%	20	2.642	5,604	-	-	-	20	2.642	5,604	24%	0%	24%
Maine	58%	28	2.681	7,486	-	-	-	28	2.681	7,486	32%	0%	32%
Massachusetts	16%	22	1.619	4,353	2	1.498	5,800	24	3.117	10,153	31%	44%	37%
New Hampshire	20%	8	0.691	2,208	-	-	-	8	0.691	2,208	36%	0%	36%
Rhode Island	16%	-	-	-	3	0.555	2,019	3	0.555	2,019	0%	42%	42%
Vermont	20%	9	0.549	1,591	-	-	-	9	0.549	1,591	33%	0%	33%
Total	**20%**	**87**	**8.182**	**21,241**	**5**	**2.053**	**7,818**	**92**	**10.235**	**29,060**	**30%**	**43%**	**32%**

Table 2–12 is the 20% Energy Full Queue plus Best By State site breakdown. This scenario exhibits the lowest overall capacity factor of 34% due to emphasis on using in-state wind development to supply a significant portion of each state's annual energy demand, thereby requiring the incorporation of many sites with significantly lower capacity factors. The 24% capacity factor of Connecticut-based wind plants highlights this fact.

2.3.5.5 Maritimes + Full Queue – 20 % Energy

The 20% Energy Full Queue plus Best Sites Maritimes scenario represents a total of 8.96 GW of installed wind capacity. Wind projects included are all of those in the Full Queue, and the addition of the best (by capacity factor) onshore Maritime sites sufficient to meet the 20% regional energy target. It is assumed that all of the wind power generated in the Maritimes will be exported to the New England Control Area without any filtering or smoothing of the energy flow by the Maritimes systems (i.e. all volatility is exported).

Figure 2–13 is an illustration of sites included in the 20% Energy Full Queue plus Maritimes scenario. Depicted in red are sites located in the Maritimes, which exhibit a moderate spatial diversity within the Maritime region, with greater penetrations in Nova Scotia and Prince Edward Island, and much less in New Brunswick.

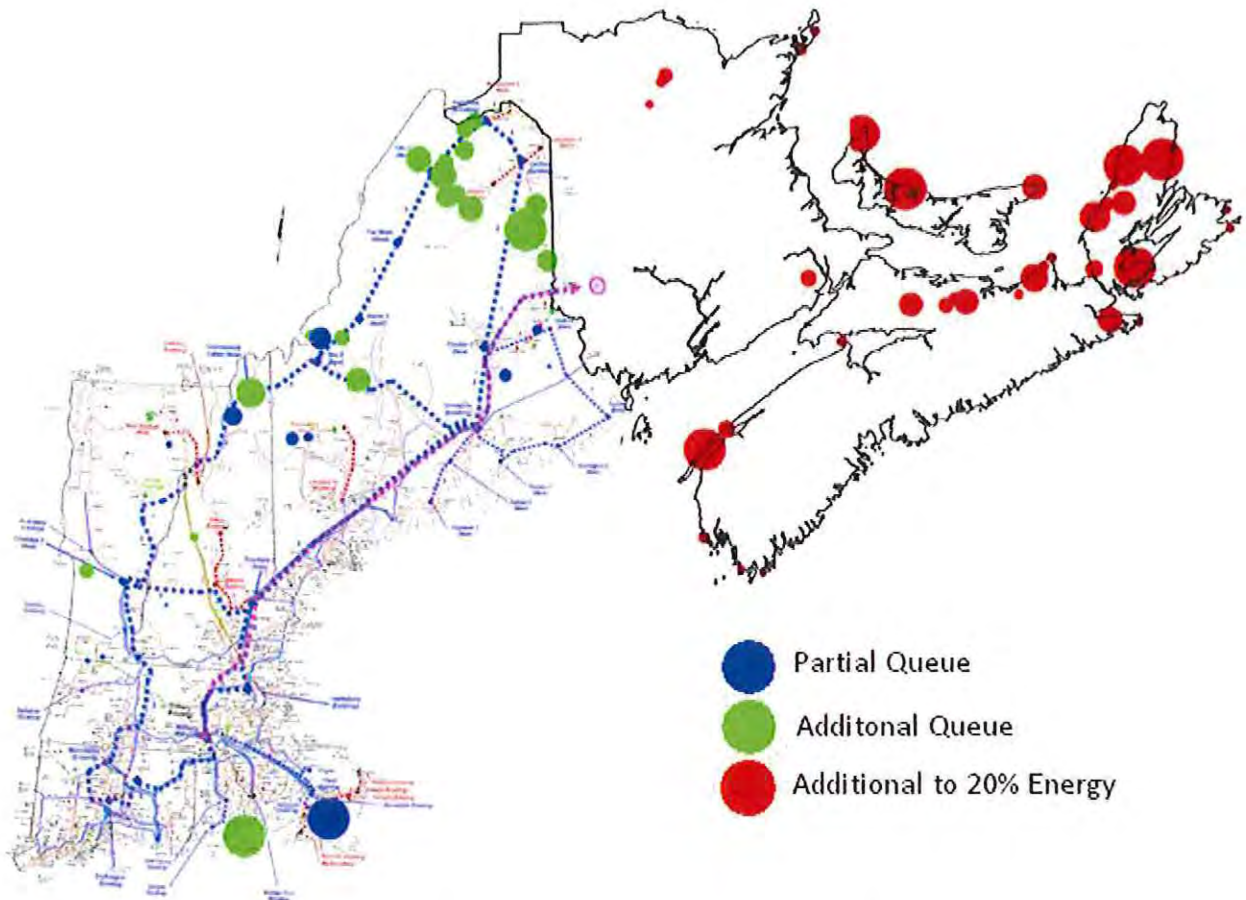

Figure 2–13 20% Energy Full Queue plus Best Sites Maritimes wind site locations

Table 2–13 20% Energy Full Queue plus Best Sites Maritimes site breakdown

		Onshore			Offshore			Total			Capacity Factor (%)		
State	% Energy by State	Site Count	Name Plate (GW)	Energy (GWh)	Site Count	Name Plate (GW)	Energy (GWh)	Site Count	Name Plate (GW)	Total Energy (GWh)	Onshore	Offshore	Total
Connecticut	0%	-	-	-	-	-	-	-	-	-	0%	0%	0%
Maine	58%	28	2.681	7,486	-	-	-	28	2.681	7,486	32%	0%	32%
Massachusetts	3%	3	0.059	183	1	0.460	1,615	4	0.519	1,798	35%	40%	40%
New Hampshire	12%	5	0.400	1,290	-	-	-	5	0.400	1,290	37%	0%	37%
Rhode Island	10%	-	-	-	1	0.360	1,295	1	0.360	1,295	0%	41%	41%
Vermont	7%	5	0.209	584	-	-	-	5	0.209	584	32%	0%	32%
Maritimes		35	4.787	16,607	-	-	-	35	4.787	16,607	40%	0%	40%
Total	20%	76	8.136	26,150	2	0.820	2,910	78	8.956	29,060	37%	41%	37%

Table 2–13 is the 20% Energy Full Queue plus Best Sites Maritimes site breakdown. A total of 35 wind plants located in the Maritimes exhibit a 40% capacity factor, and contribute an average annual energy output of 16,607 GWh, or slightly more than half of 20% of New England's forecasted (average) regional energy demand. Due to the quality of the wind resource in the Maritimes, the overall average capacity of this scenario is 37%, which rivals the balance case.

2.3.6 *Medium Penetration Scenarios - 14%Energy*

The 14% energy cases serve as midpoint cases between the Full Queue buildout and the 20% cases, and are a subset of the 20% scenarios. As such, the overall pattern of wind development of the 14% scenarios are identical (but with a lower installed wind capacity) to their respective 20% scenario counterparts, which are all described in detail above. Therefore, the discussion of each of the 14% scenarios that follows below will focus mainly on the differences relative to the 20% scenarios to avoid repetition. All 14% energy cases use the Governors' 2 GW overlay.

2.3.6.1 *Best Onshore + Full Queue – 14% Energy*

The 14% Energy Full Queue plus Best Onshore scenario represents a total of 6.75 GW of installed wind capacity. Figure 2–14 is an illustration of all scenario sites, which are broken down categorically in Table 2–14. Similar to the 20% Best Onshore scenario, the non-Queue component of the 14% onshore scenario is comprised predominantly of wind plants located in Maine. A total of 44 onshore sites (16 of which are non-Queue sites) are located in Maine with an aggregate nameplate capacity of 4,584 MW, generating an average annual output of 13,281

GWh, or more than 65% of the total wind energy generated in this scenario. Most of the sites that were omitted from the 20% Best Onshore scenario to create this scenario were located in Maine; 19 wind plants totaling 2,417 GW in nameplate capacity were removed from Maine, whereas a total of only 8 sites were removed from Massachusetts, New Hampshire and Vermont combined, with an aggregate capacity of 616 MW.

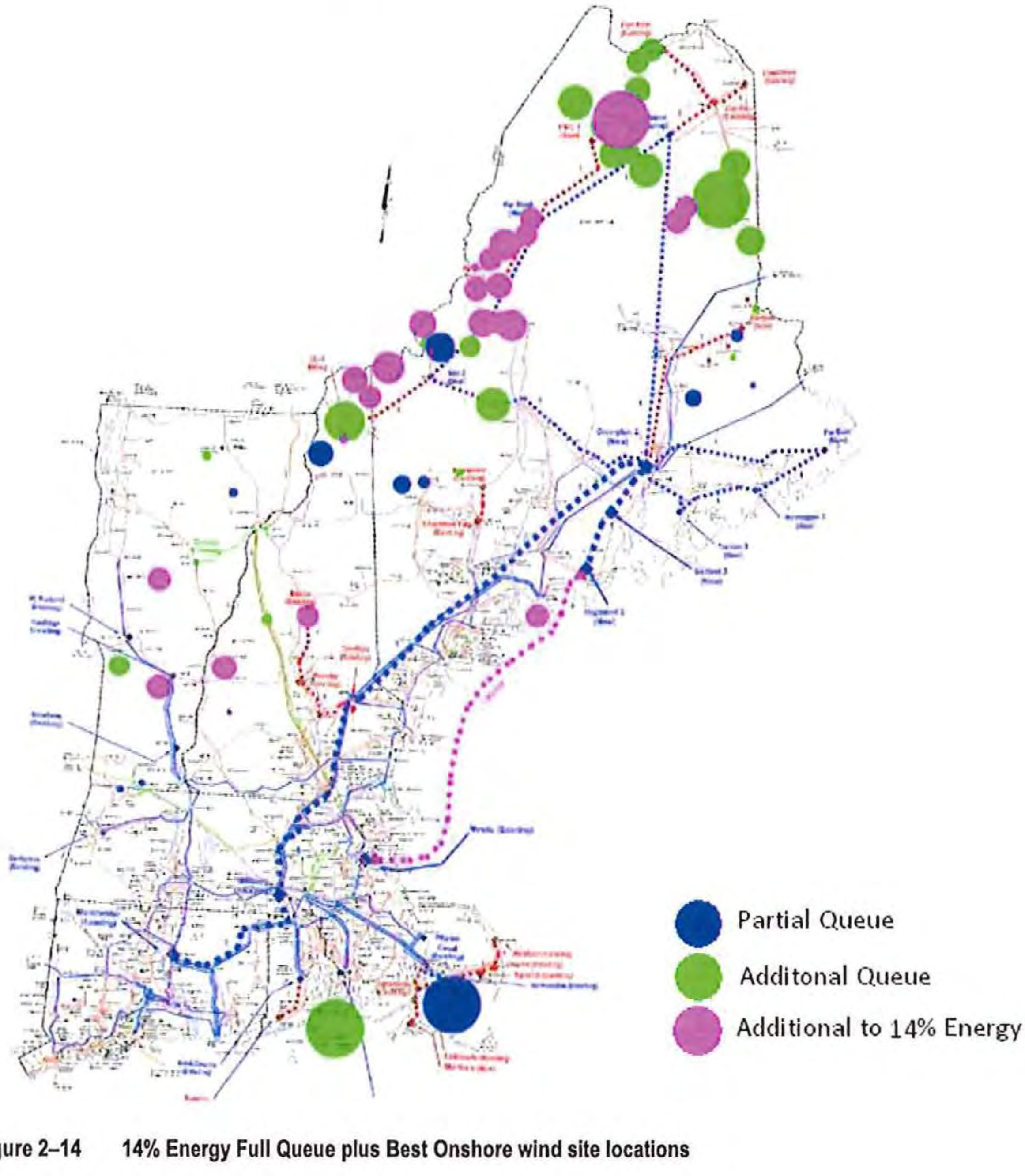

Figure 2–14 14% Energy Full Queue plus Best Onshore wind site locations

Table 2–14 14% Energy Full Queue plus Best Onshore site breakdown

State	% Energy by State	Onshore			Offshore			Total			Capacity Factor (%)		
		Site Count	Name Plate (GW)	Energy (GWh)	Site Count	Name Plate (GW)	Energy (GWh)	Site Count	Name Plate (GW)	Total Energy (GWh)	Onshore	Offshore	Total
Connecticut	0%	-	-	-	-	-	-	-	-	-	0%	0	0%
Maine	103%	44	4.584	13,281	-	-	-	44	4.584	13,281	33%	0%	33%
Massachusetts	3%	3	0.059	183	1	0.460	1,615	4	0.519	1,798	35%	40%	40%
New Hampshire	25%	10	0.864	2,746	-	-	-	10	0.864	2,746	36%	0%	36%
Rhode Island	10%	-	-	-	1	0.360	1,295	1	0.360	1,295	0%	41%	41%
Vermont	16%	7	0.419	1,223	-	-	-	7	0.419	1,223	33%	0%	33%
Total	**14%**	**64**	**5.926**	**17,432**	**2**	**0.820**	**2,910**	**66**	**6.746**	**20,342**	**34%**	**41%**	**34%**

2.3.6.2 ***Best Offshore + Full Queue – 14% Energy***

The 14% Energy Full Queue plus Best Offshore scenario represents a total of 6.13 GW of installed wind capacity. The sites in this scenario layout are illustrated in Figure 2–15 and categorized in Table 2–15. Similar to the 20% Best Offshore scenario, wind plants (depicted in red) located off the coast of Massachusetts make up the entire non-Queue component of this 14% scenario. Four wind plants (three in Massachusetts and one in Rhode Island) totaling 2,780 MW in nameplate capacity produce 53% of the total wind energy generated in this scenario. Since the proportion of offshore resources is lower than in the 20% offshore scenario, the overall capacity factor of this scenario is lower (38% compared to 40% for the high penetration case).

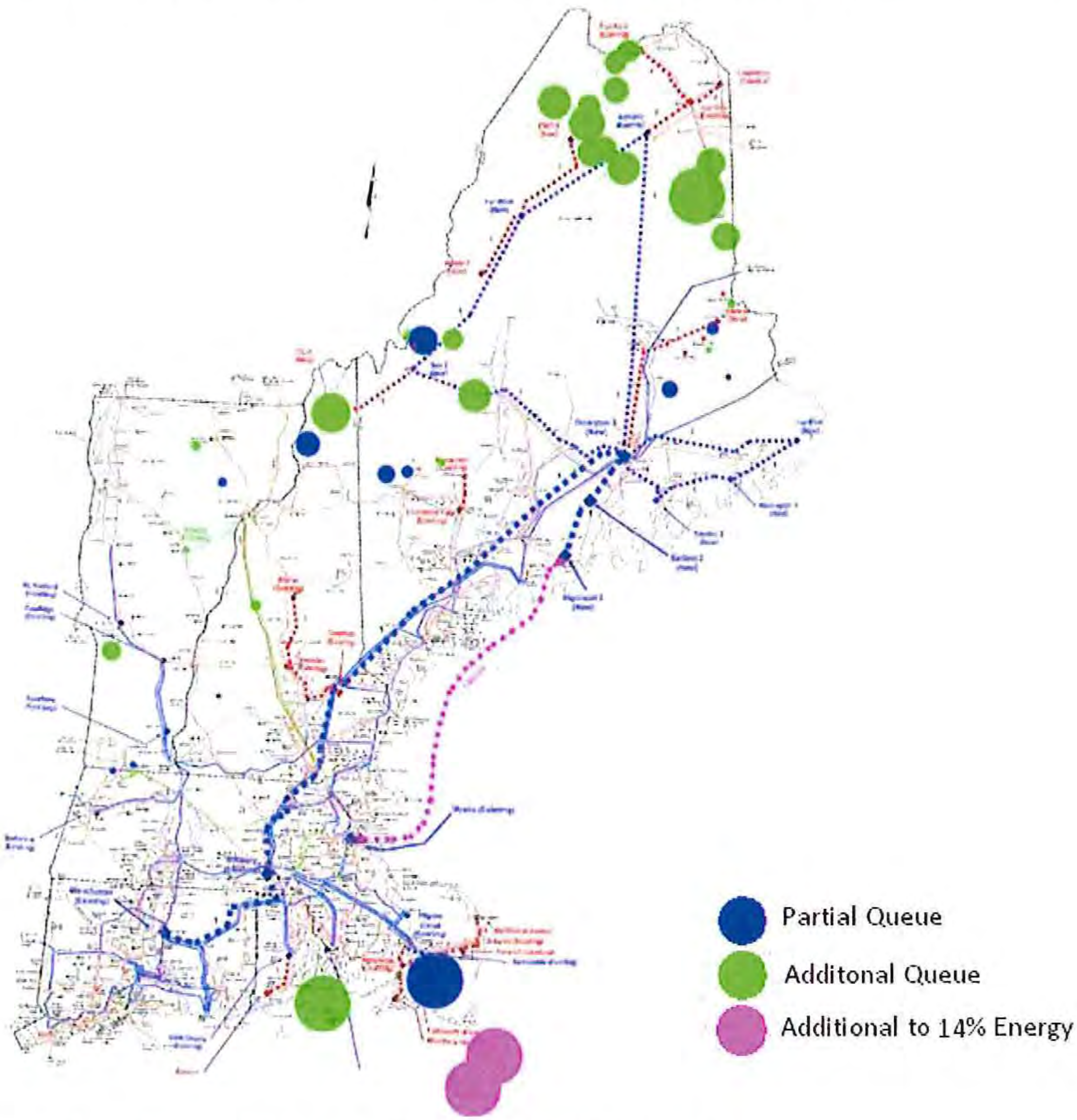

Figure 2–15 14% Energy Full Queue plus Best Offshore wind site locations

Table 2–15 14% Energy Full Queue plus Best Offshore site breakdown

State	% Energy by State	Onshore			Offshore			Total			Capacity Factor (%)		
		Site Count	Name Plate (GW)	Energy (GWh)	Site Count	Name Plate (GW)	Energy (GWh)	Site Count	Name Plate (GW)	Total Energy (GWh)	Onshore	Offshore	Total
Connecticut	0%	-	-	-	-	-	-	-	-	-	0%	0	0%
Maine	58%	28	2.681	7,486	-	-	-	28	2.681	7,486	32%	0%	32%
Massachusetts	15%	3	0.059	183	3	2.420	9,504	6	2.480	9,687	35%	45%	45%
New Hampshire	12%	5	0.400	1,290	-	-	-	5	0.400	1,290	37%	0%	37%
Rhode Island	10%	-	-	-	1	0.360	1,295	1	0.360	1,295	0%	41%	41%
Vermont	7%	5	0.209	584	-	-	-	5	0.209	584	32%	0%	32%
Total	**14%**	**41**	**3.349**	**9,543**	**4**	**2.780**	**10,799**	**45**	**6.130**	**20,342**	**33%**	**44%**	**38%**

2.3.6.3 "Balance Case" – 14% Energy

The 14% Energy Full Queue plus Balance Case represents a total of 6.31 GW of installed wind capacity. Figure 2–16 shows the graphical distribution of this scenario's sites, which are broken down categorically in Table 2–16. Similar to the 20% Balance case, offshore wind is divided evenly among Maine, Massachusetts, and Rhode Island; however, for the 14% balance case approximately 1 GW of offshore wind is developed in each of these states, rather than 1.5 GW developed in the 20% balance case. This lower proportion of offshore capacity translated into a slight reduction in overall capacity factor for the 14% case (37% rather than 38%). Another key difference is that no non-Queue onshore wind plants are required for this scenario.

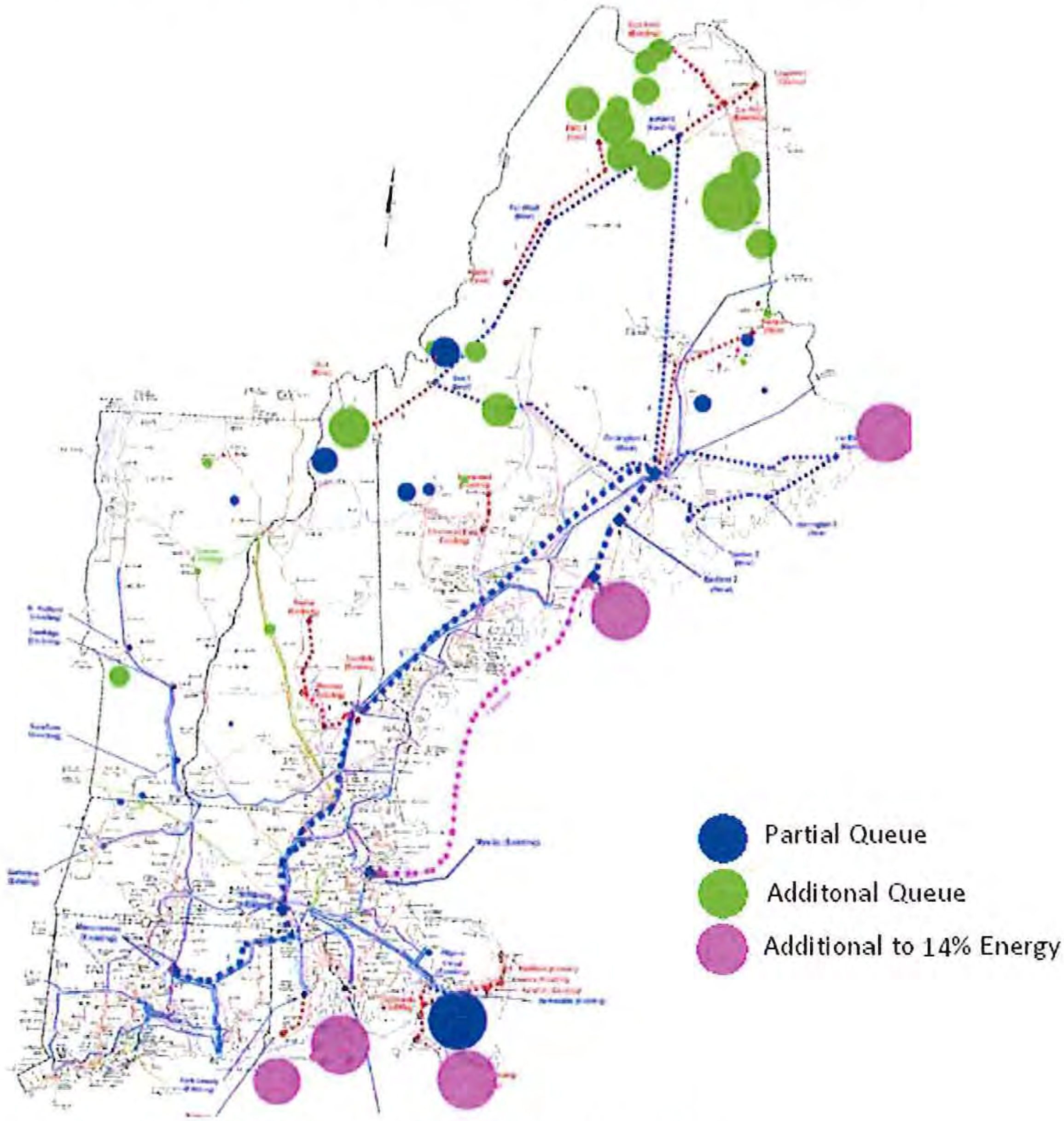

Figure 2–16 14% Energy Full Queue plus Balance Case wind site locations

Table 2–16 14% Energy Full Queue plus Balance Case site breakdown

State	% Energy by State	Onshore			Offshore			Total			Capacity Factor (%)		
		Site Count	Name Plate (GW)	Energy (GWh)	Site Count	Name Plate (GW)	Energy (GWh)	Site Count	Name Plate (GW)	Total Energy (GWh)	Onshore	Offshore	Total
Connecticut	0%	-	-	-	-	-	-	-	-	-	0%	0	0%
Maine	85%	28	2.681	7,486	2	0.986	3,523	30	3.667	11,008	32%	41%	34%
Massachusetts	6%	3	0.059	183	2	0.986	3,703	5	1.045	3,885	35%	43%	42%
New Hampshire	12%	5	0.400	1,290	-	-	-	5	0.400	1,290	37%	0%	37%
Rhode Island	28%	-	-	-	5	0.986	3,573	5	0.986	3,573	0%	41%	41%
Vermont	7%	5	0.209	584	-	-	-	5	0.209	584	32%	0%	32%
Total	14%	41	3.349	9,543	9	2.957	10,799	50	6.306	20,342	33%	42%	37%

2.3.6.4 Best By State + Full Queue – 14% Energy

The 14% Energy Full Queue plus Best By State scenario represents a total of 7.25 GW of installed wind capacity. Figure 2–17 is an illustration of this scenario's sites, which are broken down categorically in Table 2–17. Similar to the 20% best-by-state methodology, offshore and onshore wind plants were added to the Full Queue sites so that each state's wind portfolio could meet approximately 14% of its average annual energy demand, but again, due to the disproportionate amount of Maine wind power present in the Queue (2,681 MW generating 58% of the state's average energy demand), other state energy targets had to be lowered to satisfy the regional 14% energy target. The portion of each state's annual energy demand contributed by its instate wind portfolio include: 9% for Connecticut, Massachusetts and Vermont, 10% for Rhode Island, and 12% for New Hampshire. In sum, the 14% Best-By-state scenario is comprised of a total of 67 onshore sites with an aggregate capacity of 6,142 MW and 3 offshore sites with an aggregate capacity of 1,110 MW (versus 87 onshore sites totaling 8,182 MW and 5 offshore sites totaling 2,053 MW for the 20% case). Similar to the 20% Best-By-State scenario, this scenario exhibits the lowest overall capacity factor of all the 14% energy cases.

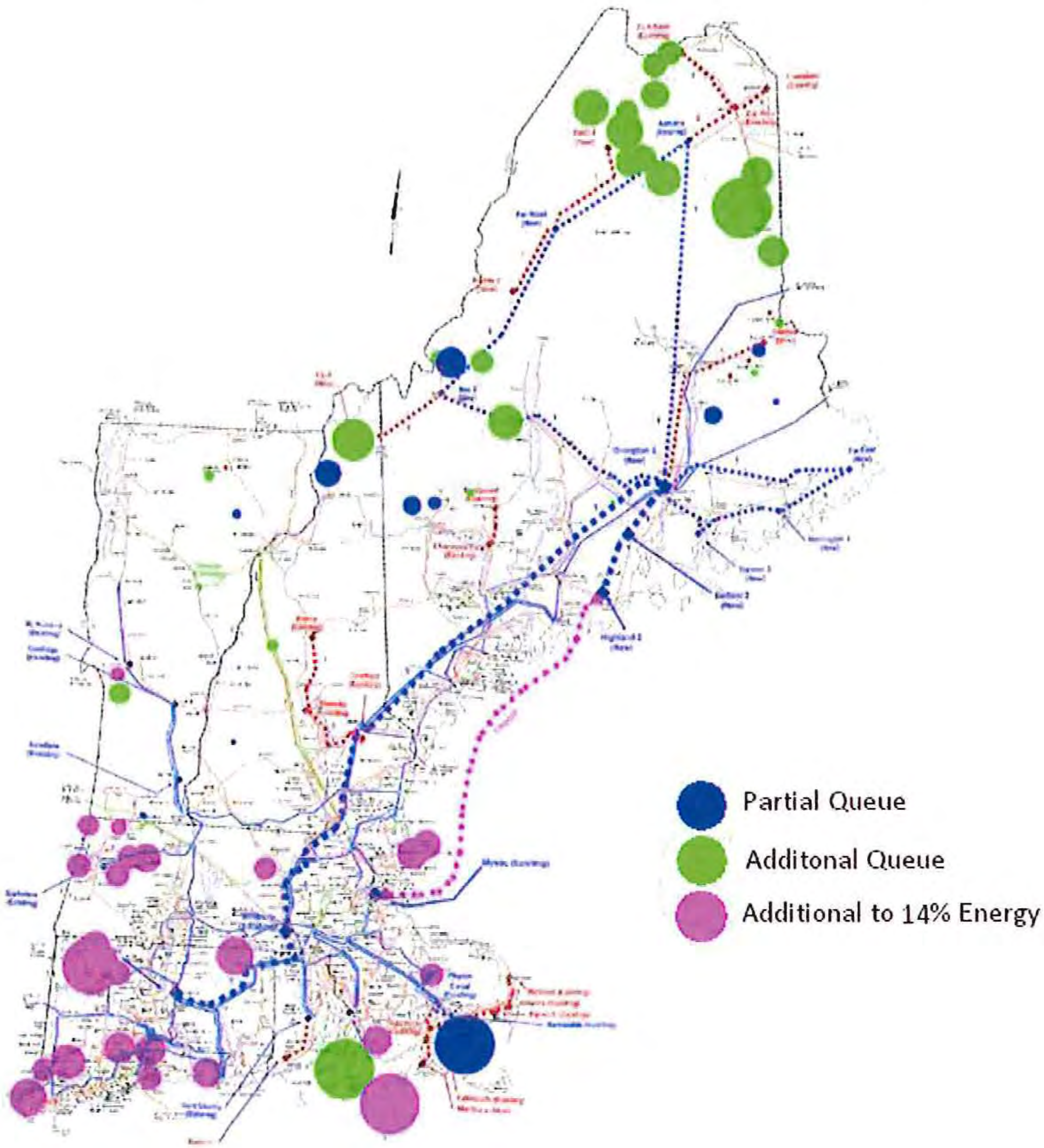

Figure 2–17 14% Energy Full Queue plus Best By State wind site locations

Table 2–17 14% Energy Full Queue plus Best By State site breakdown

State	% Energy by State	Onshore			Offshore			Total			Capacity Factor (%)		
		Site Count	Name Plate (GW)	Energy (GWh)	Site Count	Name Plate (GW)	Energy (GWh)	Site Count	Name Plate (GW)	Total Energy (GWh)	Onshore	Offshore	Total
Connecticut	9%	11	1.522	3,306	-	-	-	11	1.522	3,306	25%	0	25%
Maine	58%	28	2.681	7,486	-	-	-	28	2.681	7,486	32%	0%	32%
Massachusetts	9%	17	1.272	3,454	2	0.750	2,766	19	2.022	6,220	31%	42%	35%
New Hampshire	12%	5	0.400	1,290	-	-	-	5	0.400	1,290	37%	0%	37%
Rhode Island	10%	-	-	-	1	0.360	1,295	1	0.360	1,295	0%	41%	41%
Vermont	9%	6	0.267	744	-	-	-	6	0.267	744	32%	0%	32%
Total	14%	67	6.142	16,281	3	1.110	4,061	70	7.252	20,342	30%	42%	32%

2.3.6.5 Maritimes + Full Queue – 14% Energy

The 14% Energy Full Queue plus Best Sites Maritimes scenario represents a total of 6.39 GW of installed wind capacity. Figure 2–18 depicts the spatial distribution of this scenario's sites, which are broken down categorically in Table 2–18. This scenario is identical to its 20% counterpart except that 18 Maritimes sites have been omitted, giving a total Maritimes nameplate wind capacity of 2,225 MW instead of 4,787 MW (in the 20% case).

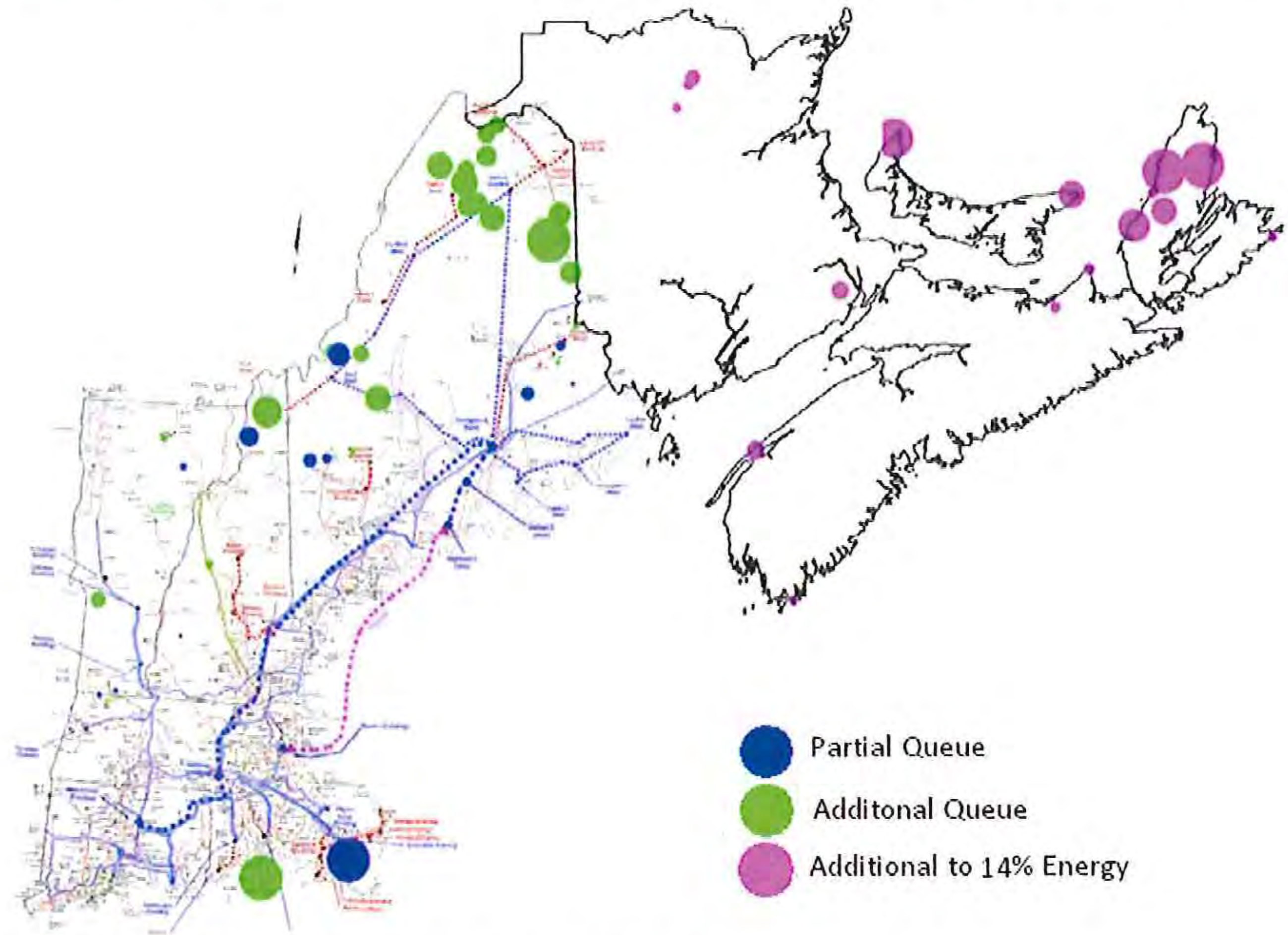

Figure 2–18 14% Energy Full Queue plus Best Sites Maritimes wind site locations

Table 2–18 14% Energy Full Queue plus Best Sites Maritimes site breakdown

State	% Energy by State	Onshore Site Count	Onshore Name Plate (GW)	Onshore Energy (GWh)	Offshore Site Count	Offshore Name Plate (GW)	Offshore Energy (GWh)	Total Site Count	Total Name Plate (GW)	Total Energy (GWh)	Capacity Factor (%) Onshore	Capacity Factor (%) Offshore	Capacity Factor (%) Total
Connecticut	0%	-	-	-	-	-	-	-	-	-	0%	0	0%
Maine	58%	28	2.681	7,486	-	-	-	28	2.681	7,486	32%	0%	32%
Massachusetts	3%	3	0.059	183	1	0.460	1,615	4	0.519	1,798	35%	40%	40%
New Hampshire	12%	5	0.400	1,290	-	-	-	5	0.400	1,290	37%	0%	37%
Rhode Island	10%	-	-	-	1	0.360	1,295	1	0.360	1,295	0%	41%	41%
Vermont	7%	5	0.209	584	-	-	-	5	0.209	584	32%	0%	32%
Maritimes		17	2.225	7,889	-	-	-	17	2.225	7,889	40%	0%	40%
Total	**14%**	**58**	**5.574**	**17,432**	**2**	**0.820**	**2,910**	**60**	**6.394**	**20,342**	**36%**	**41%**	**36%**

2.3.7 Extra-High Penetration Scenarios - 12 GW Wind

The extra-high wind penetration scenarios were designed to identify operational issues in the region's bulk power system at wind penetrations exceeding 20%. Starting with their 20% scenario counterpart, the 20% Energy Full Queue plus Best Sites Onshore scenario, they were developed by the addition of other NEWRAM sites that have the next highest capacity factors. As such, their descriptions below will focus mainly on the characteristics of the wind plants that were not present in the 20% scenarios. The extra-high wind penetration scenarios use the Governors' 8 GW Overlays.

2.3.7.1 ***Best Onshore + Full Queue – 12 GW Wind***

The Best Onshore 12 GW scenario represents a total wind energy output equivalent to approximately 24% of the region's annual energy demand. Figure 2–19 depicts the spatial distribution of this scenario's sites, which are broken down categorically in Table 2–19. A total of 22 additional sites relative to the 20% best onshore case (9.78 GW wind capacity), are scattered throughout Maine (11 additional sites), Massachusetts (one additional site), New Hampshire (five additional sites), and Vermont (five additional sites).

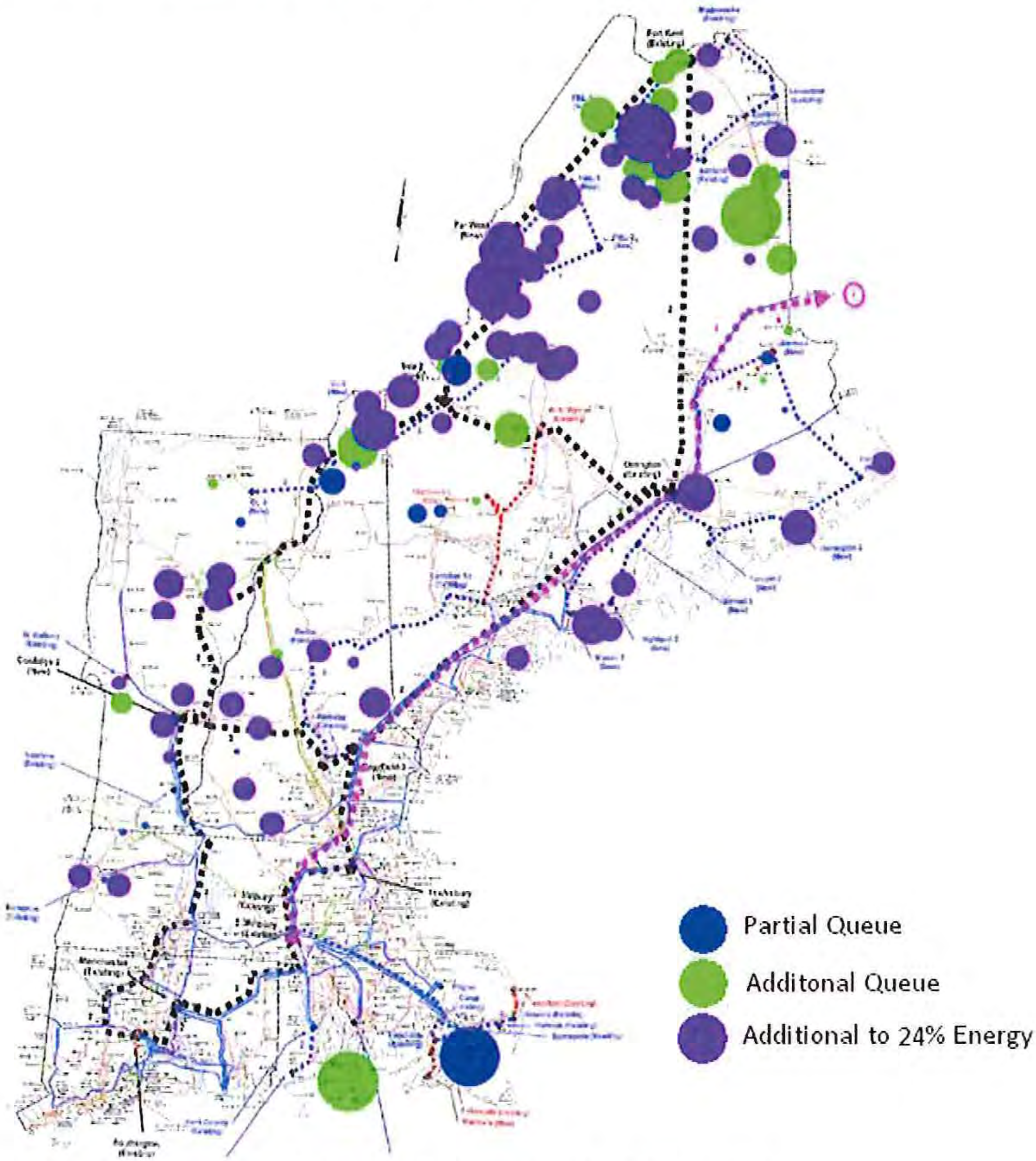

Figure 2–19 Locations of Best Onshore and Full Queue sites for 12 GW Nameplate

Table 2–19 Breakdown of Best Onshore and Full Queue sites for 12 GW Nameplate

State	% Energy by State	Onshore			Offshore			Total			Capacity Factor (%)		
		Site Count	Name Plate (GW)	Energy (GWh)	Site Count	Name Plate (GW)	Energy (GWh)	Site Count	Name Plate (GW)	Total Energy (GWh)	Onshore	Offshore	Total
Connecticut	0%	-	-	-	-	-	-	-	-	-	0%	0	0%
Maine	178%	72	7.966	22,935	-	-	-	72	7.966	22,935	33%	0%	33%
Massachusetts	4%	7	0.279	800	1	0.460	1,615	8	0.739	2,415	33%	40%	37%
New Hampshire	44%	17	1.629	4,897	-	-	-	17	1.629	4,897	34%	0%	34%
Rhode Island	10%	-	-	-	1	0.360	1,295	1	0.360	1,295	0%	41%	41%
Vermont	40%	16	1.113	3,159	-	-	-	16	1.113	3,159	32%	0%	32%
Total	24%	112	10.987	31,792	2	0.820	2,910	114	11.807	34,701	33%	41%	34%

2.3.7.2 Best Offshore + Full Queue – 12 GW Wind

The Best Offshore 12 GW scenario represents a total wind energy output equivalent to approximately 24% of the region's annual energy demand in order to be more directly comparable to the 12 GW Best Onshore Case and is therefore not 12 GW in nameplate due to the high capacity factor of the offshore wind resource. Figure 2–20 depicts the spatial distribution of this scenario's sites, which are categorized in Table 2–20. The total nameplate capacity in this scenario is approximately 9.7 GW. Two additional offshore wind sites have been added relative to the 20% Best Offshore case; both southeast of Massachusetts and totaling to 1412 MW.

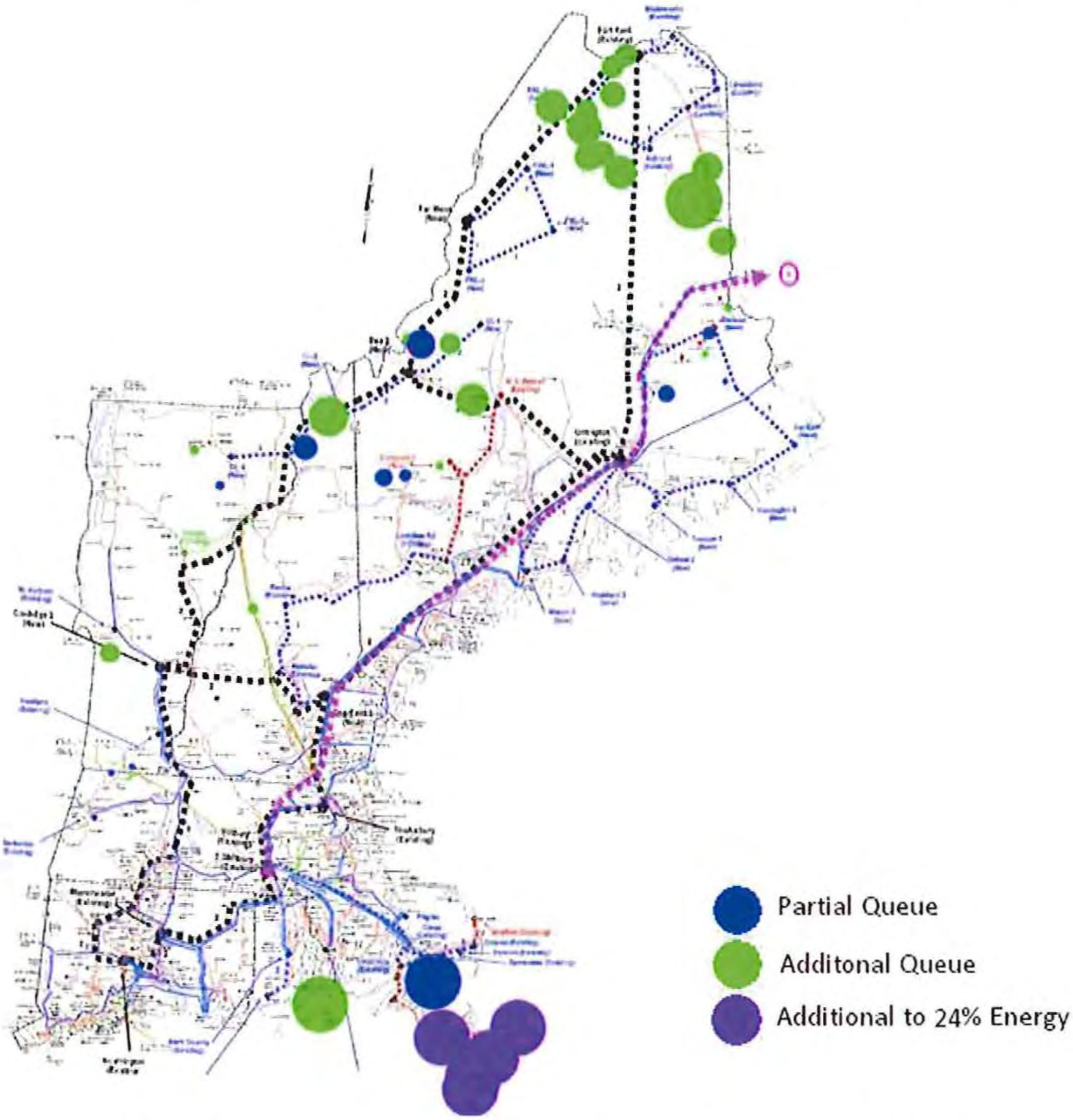

Figure 2–20 Locations of Best Offshore and Full Queue sites for comparison with 12 GW Onshore Case

Table 2–20 Breakdown of Best Offshore and Full Queue sites for comparison with 12 GW Onshore Case

State	% Energy by State	Onshore			Offshore			Total			Capacity Factor (%)		
		Site Count	Name Plate (GW)	Energy (GWh)	Site Count	Name Plate (GW)	Energy (GWh)	Site Count	Name Plate (GW)	Total Energy (GWh)	Onshore	Offshore	Total
Connecticut	0%	-	-	-	-	-	-	-	-	-	0%	0%	0%
Maine	58%	28	2.681	7,486	-	-	-	28	2.681	7,486	32%	0%	32%
Massachusetts	37%	3	0.059	183	7	5.997	23,862	10	6.056	24,045	35%	45%	45%
New	12%	5	0.400	1,290	-	-	-	5	0.400	1,290	37%	0%	37%
Rhode Island	10%	-	-	-	1	0.360	1,295	1	0.360	1,295	0%	41%	41%
Vermont	7%	5	0.209	584	-	-	-	5	0.209	584	32%	0%	32%
Total	**24%**	**41**	**3.349**	**9,543**	**8**	**6.357**	**25,157**	**49**	**9.706**	**34,700**	**33%**	**45%**	**41%**

2.3.8 Sensitivity Cases

Sensitivity cases were also run using the 2006 year wind/load scenarios in order to investigate the influence that additional changes may have with regard to integrating large-scale of wind power for New England. These sensitivity cases include:

1. Double interface capability (Hydro-Quebec, New York, New Brunswick)

2. Quadrupling only the New Brunswick interface capability especially due to the large potential wind resource there.

3. Increasing the cost of carbon emissions from \$0 per ton to a mid-case of \$40 per ton to a high case of \$65 per ton in order to investigate changes in dispatch.

4. Fuel price sensitivity – high and low with regard to base. The NEWIS assumed future prices based on the 2009 Energy Information Administration (EIA) Annual Energy Outlook.[59] EIA projects higher natural gas and oil prices, and relatively stable coal, biomass, and nuclear prices, over the long term.

[59] Energy Information Administration, 2009 Annual Energy Outlook, DOE/EIA-0383 (Washington DC: U.S. DOE, April 2009); http://www.eia.doe.gov/oiaf/aeo/index.html

5. A combination of high fuel prices and high carbon cost, low fuel prices and high carbon cost to not only account for a possible range of fuel price scenarios, but also to attempt to account for potential changes in fuel costs that may impact one fuel with respect to another (e.g. natural gas vs. coal).

6. Storage sensitivity – The impact of increased storage, based on utilization. Since this sensitivity was based on the utilization of existing storage and since (as will be seen later in this report) the existing storage was not fully utilized, this sensitivity case was not investigated.

7. Wind Forecast impacts – (No forecast, state-of-the-art forecast, perfect forecast) in order to investigate the operational effects of improving the wind power forecast.

2.3.9 Development of Transmission Overlays

2.3.9.1 Introduction

The location of much of the high capacity factor potential wind resource in New England does not correlate well with areas of high population and concentrated energy demand. In general, the region's population and electricity demand are concentrated in southern New England, while the best onshore wind resources are located in the north. This lack of spatial coincidence introduces a need for new transmission to connect potential wind resources to load centers throughout the region. Potential offshore wind resources are located much closer to load centers significantly reducing the amount of required transmission. Since a primary objective of the NEWIS is to identify the operational effects of large-scale integration of wind power, the role of transmission cannot be understated, especially given that many potential wind plants in New England could not feasibly be built and operated without the construction of new transmission. Figure 2–21 illustrates the poor correlation in the locations of regional wind resource and areas of greatest electricity demand.

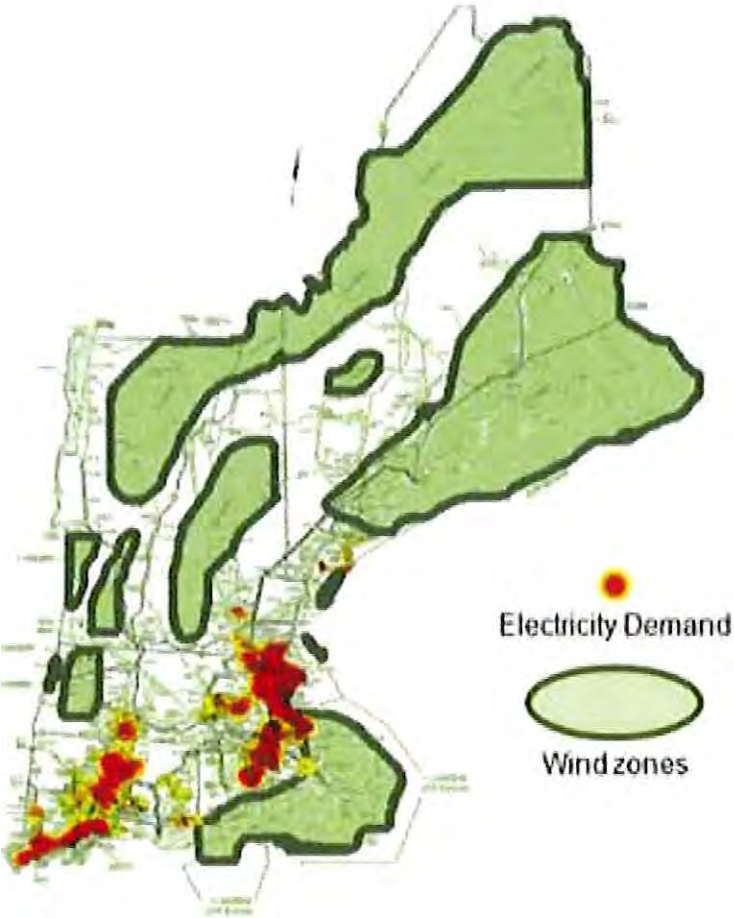

Figure 2–21 Potential wind zones and load centers in New England (Gov. Study, p. 6)

The NEWIS used three transmission overlays previously developed as part of a 2009 economic study conducted by the ISO for the New England Governors, hereafter referred to as the Governors' Study.[60] The following four transmission systems were developed and used for the NEWIS:

- 2019 ISO-NE System ("existing") – used for base case.
- Governors' 2 GW Overlay – used as developed for Governor's Study.

[60] New England 2030 Power System Study (February 2010); http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2010/economicstudyreportfinal_022610.pdf.

- Governors' 4 GW Overlay/1,500 MW New Brunswick Interchange – An additional 345 kV line taken from the 8 GW Overlay was included for Southeastern Massachusetts in this overlay.
- Governors' 8 GW Overlay/1,500 MW New Brunswick Interchange

Due to scope constraints, only thermal limits were developed, investigated, and utilized for the NEWIS study. Voltage and stability limits would very likely reduce assumed transfer capability so the transfer capabilities of the hypothesized transmission expansion assumed in the study should be considered an upper bound.

Each of these systems is described in detail in subsequent sections below; however, a description of the Governor's Study is required first since the transmission used for the NEWIS is largely based on overlays developed for the Governor's Study.

2.3.9.2 Governor's Study

The Governor's Study adapted potential wind resources identified during a 2008 study conducted for the ISO by Levitan & Associates Inc. (LAI).[61] Since LAI used AWST's MesoMap system and a similar screening process as the NEWIS to identify viable wind resources, there is a strong geo-correlation of wind resources identified in both studies. Therefore, potential transmission identified for the Governor's Study is well-suited for the NEWIS.

This study identified potential transmission necessary to integrate a range of renewable resource expansion scenarios.[62] The base case or "constrained" case was selected using interface limit assumptions set forth in ISO's 2009 Regional System Plan (RSP)[63] (this system is referred to as the '2019 ISO-NE system', and is described further in the next section). The transmission overlays were designed to be robust, workable, and to ensure 100% deliverability of the renewable resources selected, i.e. the bulk power system was made "unconstrained" under each

[61] Phase II Wind Study (Levitan & Associates Inc., March 2008) http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2008/may202008/lai_5-20-08.pdf

[62] The ISO retained the consulting firm, Energy Initiatives Group (EIG), to develop the transmission overlays.

[63] The interface limits modeled in the Governor's Study assume the completion of the New England East-West Solution (NEEWS) and the Maine Power Reliability Project (MPRP) transmission projects identified in the Regional System Plan; see http://www.iso-ne.com/trans/rsp/2009/rsp09_final.pdf.

of the wind scenarios used in the Governor's Study.[64] The overlay design was strictly conceptual, considering only single-contingency thermal constraints.[65] Additionally, the Governor's study did not evaluate the feasibility of siting specific transmission projects, and potential transmission identified does not represent the future location of facilities; however, efforts were made to site potential transmission within existing rights-of-way while also accounting for alternative power flow paths in the event of a contingency. In general, the results of the study found a need for higher voltage classes of transmission introduced as the wind penetration gets significantly large (i.e. greater than 4 GW installed nameplate capacity).

Given that the core objectives of the Governor's Study were economic in nature, EIG developed preliminary order-of-magnitude cost-estimate ranges for each of the conceptual transmission expansions used. Note that no additional cost analyses or considerations regarding hypothetical transmission used were made for the NEWIS. Therefore, it is advised that readers interested in preliminary transmission costing refer to the Governor's Study.

2.3.9.3 Development of Overlays for NEWIS

In contrast to the Governor's Study, for which transmission overlays served only as wind delivery systems connected to the bulk system at major load centers, the overlays were integrated into the regional transmission system for the NEWIS. All collocated substations of the overlays and the 2019 ISO-NE system were tied together, thus allowing the overlays to act as conduits for loads and power generated by other sources, rather than just the wind. This was critical to developing hypothetical transmission that enables a realistic simulation of generation dispatch, which thereby yields realistic LMPs.

Wind build-out scenarios were matched with Governor's Study transmission overlay configurations and a preliminary copper sheet simulation was run to determine their respective suitability. Based on the copper sheet simulations and the developed thermal transfer limits, the overlays were found to be able to support more wind power than the wind scenarios used in the Governor's Study. For example, the Governors' 4 GW overlay, which was developed to be able to robustly deliver a total additional generation (i.e. wind)nameplate capacity of 4 GW, was

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[64] Transmission constraints are the physical limitations of the bulk power system that reduce the ISO's ability to dispatch the lowest-priced resources to meet the regional electricity demand. Due to these constraints, the ISO may have to dispatch higher-priced resources, and the incremental increase in cost is reflected in wholesale electricity prices as congestion costs.

[65] Typical transmission designs are subjected to technical optimization and a rigorous voltage and stability analyses.

capable of transporting wind penetrations in the 20% energy scenario, or up to 9.77 GW of wind. The primary reasons smaller overlays are able to be used are that typical capacity factors of wind plants are between 20% and 45% due to the resource's variable nature and that geographic diversity limits the coincident output of the wind power fleet; nameplate, fully coincident output values were used for the Governor's Study. Thus, from a thermal transfer limit standpoint only, the overlays used in the Governor's Study are designed to address the long term expansion of the system beyond the immediate concern of integrating the wind generation postulated in the various scenarios. In consideration of wind plant interconnection, it is assumed that wind plants in each scenario are connected directly to the overlays. In effect this means that all local transmission needed to connect the wind to the overlays was presumed to already exist and that it is sufficiently robust to be unconstrained in all of the NEWIS wind scenarios. Because of this, during operational simulations conducted as part of the NEWIS, local transmission is "invisible" to the system. This is an important consideration in that the reader should not assume that for the study local transmission congestion could impede the deliverability of the wind to the larger transportation model. In fact due to the typical development pattern of wind generation facilities in New England and their interconnection under the minimum interconnection standards process, local interconnections are often the point at which congestion occurs which results in potential wind curtailments.

2.3.9.4 Validation of Power Flow Cases

ISO-NE provided GE the 2019 power flow base case. Based on the transmission overlay developed by EIG, GE built three additional power flow cases (Governors' 2 GW overlay, Governors' 4 GW overlay and Governors' 8 GW overlay) and delivered these to ISO-NE in PSSE RAW format.

ISO-NE then used Power World Simulator version 14 to validate that the power flow cases built by GE were consistent with the overlay developed by EIG. Power World Simulator has a function to compare topological differences between two power flow cases. It presents a report of what elements are added and removed in the present case from the base case. The topological difference reports generated by Power World Simulator were then compared to the transmission overlay by EIG side by side to make sure that the power flow cases have represented the transmission overlay correctly. There were several iterations between ISO-NE and GE in building and validating these cases. However, detailed and extensive engineering analysis regarding stability and voltage limits would be required in order to determine the true viability of the hypothesized transmission expansions, which was outside the scope of the NEWIS.

2.3.9.5 Developments of Interface Transfer Limits

After building and validating the power flow cases, ISO-NE inserted definitions for the interfaces (see Table 2–21) between RSP subareas for the 2019 base case, 2 GW overlay case, 4 GW overlay case and 8 GW overlay case: no new interfaces were created. Transfer limits were calculated for each interface of these power flow cases by using the Available Transfer Capability (ATC) module of Power World Simulator. The calculated interface limits were later reviewed at the Planning Advisory Committee and the NEWIS Technical Review Committee and used in the operational analysis performed using General Electric's Multi Area Production Simulation (GE MAPS) program.

Table 2–21 Transfer limits between RSP subareas

Interface Limits	2019 ISO-NE	Govs 2 GW Overlay	Govs 4 GW Overlay	Govs 8 GW Overlay
New Brunswick- New England	1000	1000	1000	1000
Orrington-South	1200	2500	5500	6100
Surowiec-South	1150	2100	5200	5800
Maine-NH	1450	2700	5700	6400
North-South	2700	3800	6800	7400
Boston Import	4900	4900	4900	4900
SEMA	No Limit	No Limit	No Limit	No Limit
SEMARI	3300	4200	6500	6500
East - West	3500	4300	7900	8600
West - East		4400	5100	5800
CT Import	3600	5300	7700	8200
CT Export		4200	4900	5400
Southwest Connecticut Import	3650	3650	3650	3650
Norwalk–Stamford	1650	1650	1650	1650
Cross-Sound Cable (Export)	330	330	330	330
Cross-Sound Cable (Import)	346	346	346	346
NY–NE Summer	1525	1,525	1,525	1,525
NY–NE Winter	1600	1,600	1,600	1,600
NE–NY Summer	1200	1,200	1,200	1,200
NE–NY Winter	1325	1,325	1,325	1,325
HQ–NE (Highgate)	200	200	200	200
HQ–NE (Phase II)	1800	1,800	1,800	1,800
Note: The Transfer Capability of the HVDC in 2 GW case (Highland – Mystic) and 4 GW and 8 GW case (Keswick – Millbury) is not counted in this table				

Several elements need to be defined for each of the interface:

- Source
- Sink
- Contingencies
- Monitoring Elements

The ATC module increases power transfers from predefined Source to Sink until one of the monitoring elements reaches its limit. Normal Line Rating is respected for pre-contingency and Long Term Emergency (LTE) rating is respected for post-contingency. Once any of the monitored transmission elements reaches its limit during the power transfer, the simulation stops and the corresponding interface flow is the interface limit.

2.3.9.6 ***Base Case - 2019 ISO-NE System***

The transmission system used as a base case for the NEWIS is the one developed for the 2009 NERC Multi-regional Modeling Working Group (MMWG) Library consisting of all projects in-service across the entire Eastern Interconnection by 2020[66]. The 2019 ISO-NE system includes the existing transmission system, as well as projects listed as Planned or Under Construction (has Proposed Plan Application approval, Section I.3.9 of the ISO Tariff) on the RSP09 Transmission Project Listing.[67] The major projects included in the model are:

- Maine Power Reliability Program
- New England East West Solution
- Vermont Southern Loop Project
- Central/Western Mass Upgrades
- Greater Rhode Island Transmission Improvements
- Bangor Hydro Downeast Reliability Improvements
- National Grid Worcester Cable

[66] ISO-NE did not have any transmission projects listed in RSP09 that have an in-service date of after 2019, so the 2020 model developed for MMWG has the same topology as a 2019 system only with increased load due to load growth.

[67] RSP09 Transmission Project Listing can be found at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/projects/2009/index.html

- Substation Improvements or Additions
- ME – Keene Rd Substation – New 345/115 Autotransformer
- ME – South Gorham Substation – New 345/115 Autotransformer
- NH – Comerford Substation – New Reactive Devices
- MA – West Amesbury Substation – New 345/115 Substation
- MA – Edgar Substation – New 115 kV Reactors
- MA – Wachusett Substation – New 345/115 Autotransformer
- CT – Broadway Substation – 2 New 115/13.8 Transformers
- CT – Union Substation – New 115/13.8 Substation
- All future Queue Generation Projects that had PPA approval (Section I.3.9) as of May 2009

In the 2019 ISO-NE system (Figure 2–22), the following counties: northern Somerset, northern Oxford, Aroostook and Washington Counties in northern Maine are considered part of New Brunswick, Area 105. These counties make up a part of the region with excellent onshore wind resource. Main Public Service territory consisting of Aroostook and Washington Counties are currently served radially from New Brunswick. No wind power projects in the Partial Queue scenario are located in these counties; however, these northernmost areas are tied into the rest of the regional transmission system for all of the non-base case transmission overlays used for the NEWIS, allowing access to wind resources located there.

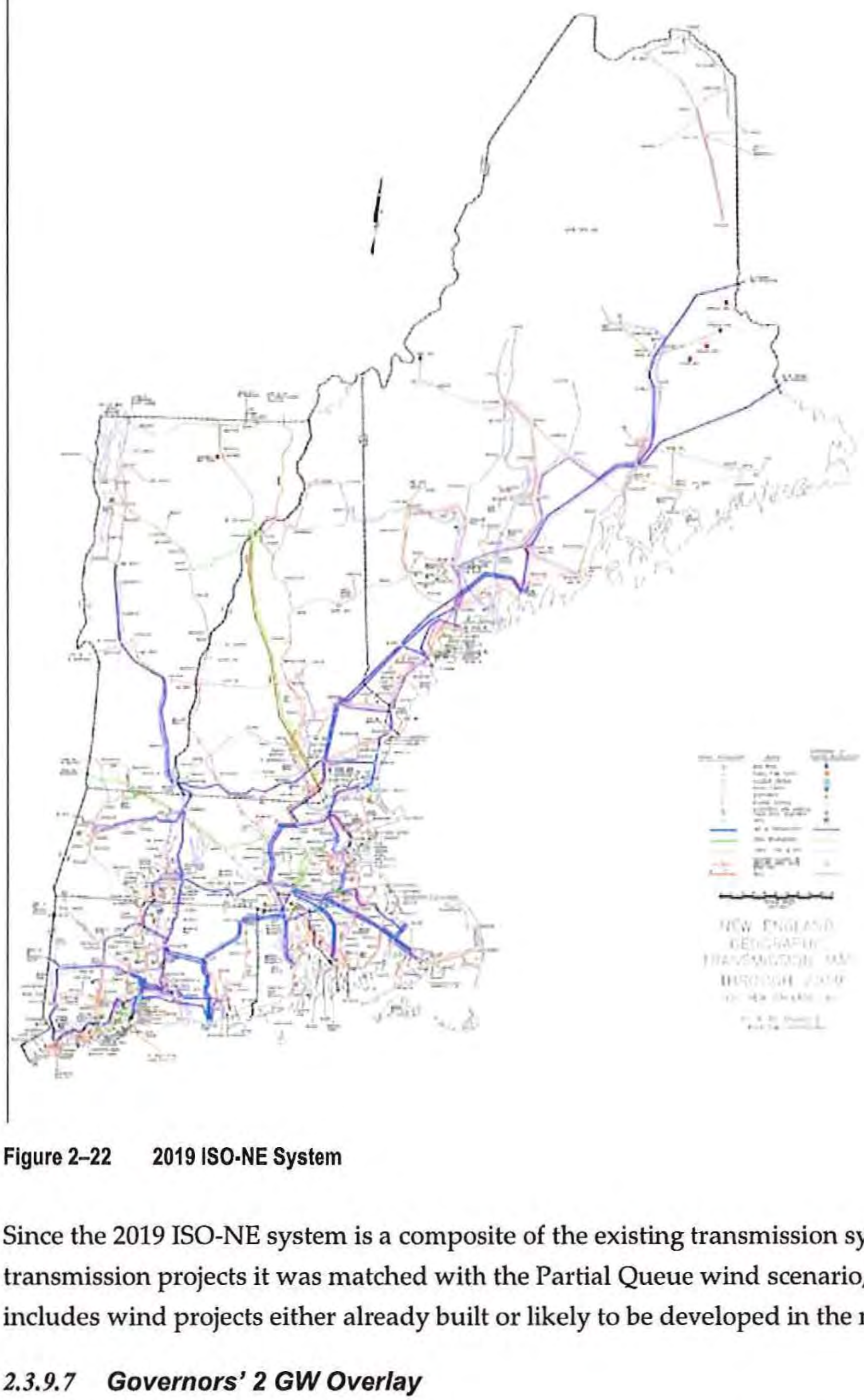


Figure 2–22 2019 ISO-NE System

Since the 2019 ISO-NE system is a composite of the existing transmission system and near-term transmission projects it was matched with the Partial Queue wind scenario, which similarly includes wind projects either already built or likely to be developed in the near-term.

2.3.9.7 ***Governors' 2 GW Overlay***

The Governors' 2 GW overlay features the identical architecture as the 2 GW onshore overlay used in the Governor's Study, elements of which are broken down in Table 2–22 below.

Table 2-22 Breakdown of 2 GW transmission overlay

CATEGORY DESCRIPTION	SUB-CATEGORY DESCRIPTION	CIRCUIT MILES	# OF SUBSTATIONS
TRANSMISSION	1. 345kV AC Backbone	355	
	2. 345kV AC / HVDC Backbone	240	
	3. 345kV Local Loops	645	
	4. 115kV Reinforcements	545	
	TOTAL	1785	
SUBSTATION	1. 345kV AC Backbone		3
	2. 345kV AC / HVDC Backbone		3
	3. 345kV Local Loops		8
	4. 115kV And 69kV Reinforcements		20
	TOTAL		34

The Governors' 2 GW overlay consists of the following potential transmission and related system upgrades relative to the 2019 ISO-NE system:

- 345kV and 115 kV local loops and radials in NH and ME to connect inland and offshore wind
- Single-circuit overhead 345 KV backbone, central ME-Millbury-Manchester, and single-circuit overhead 345 kV backbone to high-voltage direct-current (HVDC) submarine cable, ME-Boston to move energy to load centers
- Upgraded coastal substations in MA and RI with reinforced 115 kV to connect offshore wind
- Other small disbursed inland and offshore wind connect to existing 115 kV substations
- 1,785 miles of total potential new transmission circuit

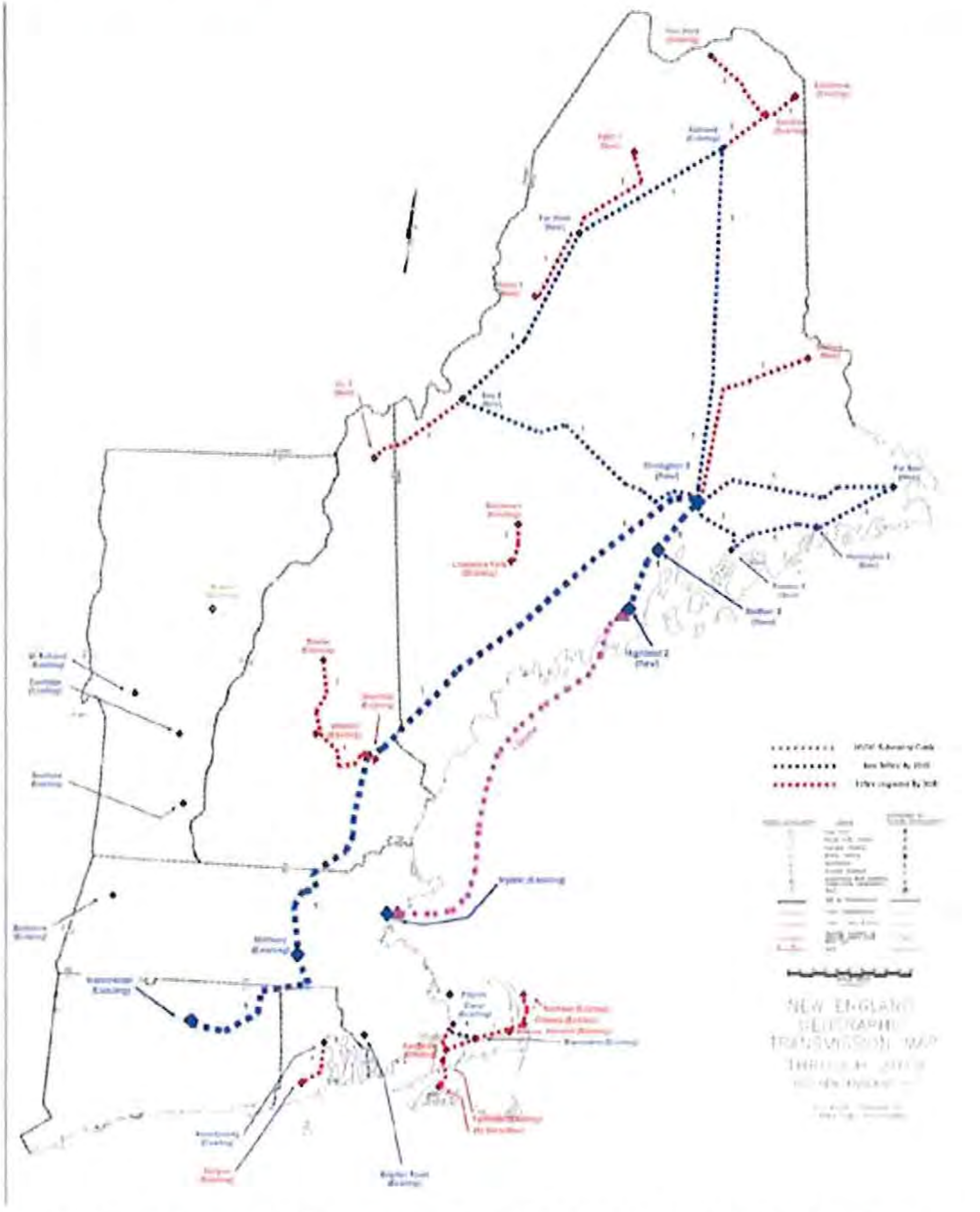


Figure 2–23 Governors' 2 GW overlay used for NEWIS Full Queue and 14% Wind Penetrations Scenarios

Figure 2–23 above is a schematic of the Governors' 2 GW overlay, this overlay was used as the transmission system for the Full Queue wind scenario and the 14% total energy wind scenarios, which include regional wind penetrations greater than 7 GW. As this is the only of the three overlays that does not feature transmission upgrades between Canal Substation and Millbury Substation in southeastern Massachusetts, it highlights constraints and operational issues in that load zone resulting from offshore wind development in Massachusetts and Rhode Island. Offshore wind development in this area includes a 460 MW wind power project which has received I.3.9 approval and therefore is considered a near-term project. Hypothetical local transmission loops acts as conduits for wind buildout in northern Maine, and thus would require integration of these areas into the jurisdiction of the Federal Energ Regulatory Commission (FERC).

2.3.9.8 Governors' 4 GW Overlay

The Governors' 4 GW overlay is a composite of the following transmission designs from the Governor's Study: 1) The 4 GW onshore overlay, which serves as the primary overlay architecture, 2) a 1,500 MW New Brunswick interconnection, and 3) additional transmission in SEMA to ensure deliverability of potential offshore in Massachusetts and Rhode Island, which is a feature of the 8 GW overlay in the Governor's Study. Of the two voltage class options outlined for this scenario in the Governor's Study, 500 kV loops were selected for use. Table 2–23 is a breakdown of all transmission and substation upgrades featured in this overlay.

Table 2–23 Breakdown of 4 GW transmission overlay

CATEGORY DESCRIPTION	SUB-CATEGORY DESCRIPTION	CIRCUIT MILES	# OF SUBSTATIONS
500kV BACKBONE LOOPS			
TRANSMISSION	1. 500kV Backbone Loops	2750	
	2. 345kV Local Loops	480	
	3. 115kV Reinforcements	465	
	SUBTOTAL	3695	
SUBSTATION	1. 500kV Backbone Loops		15
	2. 345kV Local Loops		12
	3. 115kV And 69kV Reinforcements		14
	SUBTOTAL		41
1500 MW New Brunswick Interchange			
TRANSMISSION	1. +/- 450kV HVDC Bi-Polar O/H Backbone	400	
	SUBTOTAL	400	
SUBSTATION	1. +/-450kV, 1500 MW HVDC Bi-Polar Terminal		1
	TOTAL	4095	42

The Governors' 4 GW overlay consists of the following potential transmission and related system upgrades relative to the 2019 ISO-NE system:

- 345kV and 115 kV local loops and radials in NH and ME to connect inland and offshore wind
- Dual-circuit overhead 500 kV backbones through most of interior New England
- Upgraded coastal substations with reinforced 345 kV and 115 kV to connect offshore wind in MA, RI
- Other small disbursed inland and offshore wind connect to existing 115 kV substations
- Added 345 kV line from SEMA to Millbury (element from 8 GW overlay) to connect offshore wind in MA & RI
- A New Brunswick interconnection consisting of a +/- 450 kV HVDC overhead line capable of transporting 1,500 MW of power from the Keswick area of New Brunswick south via the northern Maine border to Millbury, Massachusetts.
- 4,095 (3,695w/o NB interconnect) miles of total potential new transmission circuit

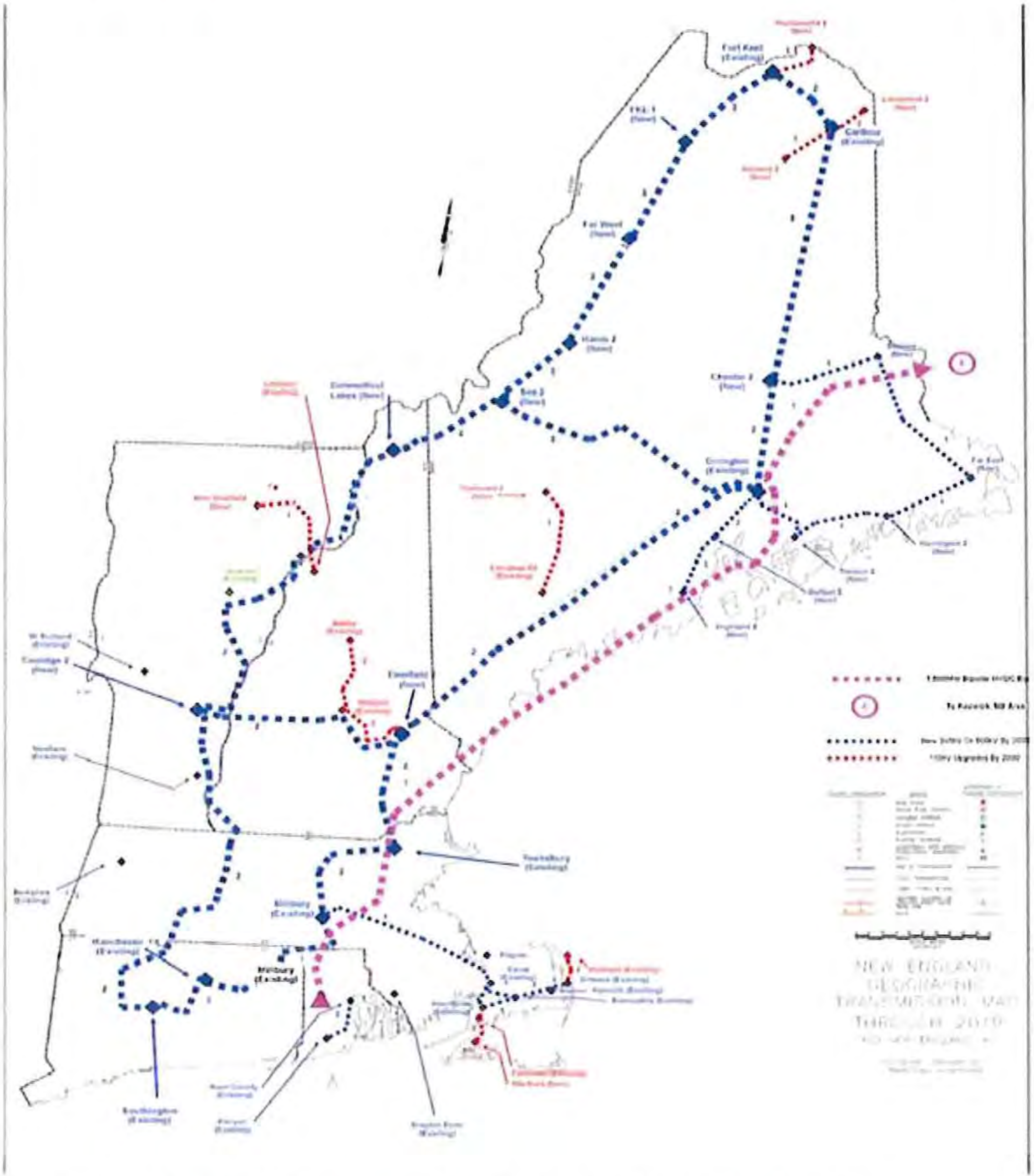


Figure 2–24 Governors' 4 GW overlay used for NEWIS 20% Wind Penetrations Scenarios

Figure 2–24 is a schematic of the Governors' 4 GW overlay. This overlay was used as the transmission system for the 20% regional energy scenarios, representing regional wind penetrations approaching 10 GW. Local loops featured for northern Maine in the 2 GW overlay are upgraded to backbone loops to deliver up to 7 GW of onshore wind hypothesized for the state (Best Onshore 20% case). Also included in the overlay is a 1500 MW HVDC line between the Maritimes (Keswick, NB) and Millbury, MA. Such an HVDC line would facilitate transfer of power between the Maritimes and ISO-NE (viz-a-viz the Maritimes Wind Scenarios).

2.3.9.9 Governors' 8 GW Overlay

The 8 GW overlay is architecturally identical to the 8 GW Governor's Study overlay, with the addition of the 1,500 MW New Brunswick interconnection. Of the two voltage class options outlined for this scenario in the Governor's Study, 500 kV loops were selected for use. Table 2–24 is a breakdown of all transmission and substation upgrades featured in this overlay.

Table 2–24 Breakdown of 8 GW transmission overlay

CATEGORY DESCRIPTION	SUB-CATEGORY DESCRIPTION	CIRCUIT MILES	# OF SUBSTATIONS
500kV BACKBONE LOOPS			
TRANSMISSION	1. 500kV Backbone Loops	2740	
	2. 345kV Local Loops	1395	
	3. 115kV Reinforcements	185	
	SUBTOTAL	4320	
SUBSTATION	1. 500kV Backbone Loops		10
	2. 345kV Local Loops		29
	3. 115kV And 69kV Reinforcements		5
	SUBTOTAL		44
1500 MW New Brunswick Interchange			
TRANSMISSION	1. +/- 450kV HVDC Bi-Polar O/H Backbone	400	
	SUBTOTAL	400	
SUBSTATION	1. +/-450kV, 1500 MW HVDC Bi-Polar Terminal		1
	TOTAL	4720	45

The 8 GW overlay consists of the following potential transmission and related system upgrades relative to the 2019 ISO-NE system:

- 345kV and 115 kV local loops and radials (NH and ME) to connect on and offshore wind
- Dual-circuit overhead 500 kV backbones through most of interior New England
- Upgraded coastal substations with reinforced 500 kV, 345 kV and 115 kV to connect offshore wind in MA, RI

- Other small disbursed inland and offshore wind connect to existing 115 kV substations
- A New Brunswick interconnection consisting of a +/- 450 kV HVDC overhead line capable of transporting 1,500 MW of power from the Keswick area of New Brunswick south via the northern Maine border to Millbury, Massachusetts.
- 4,720 (4,320 w/o NB interconnection) miles of total potential new transmission circuit

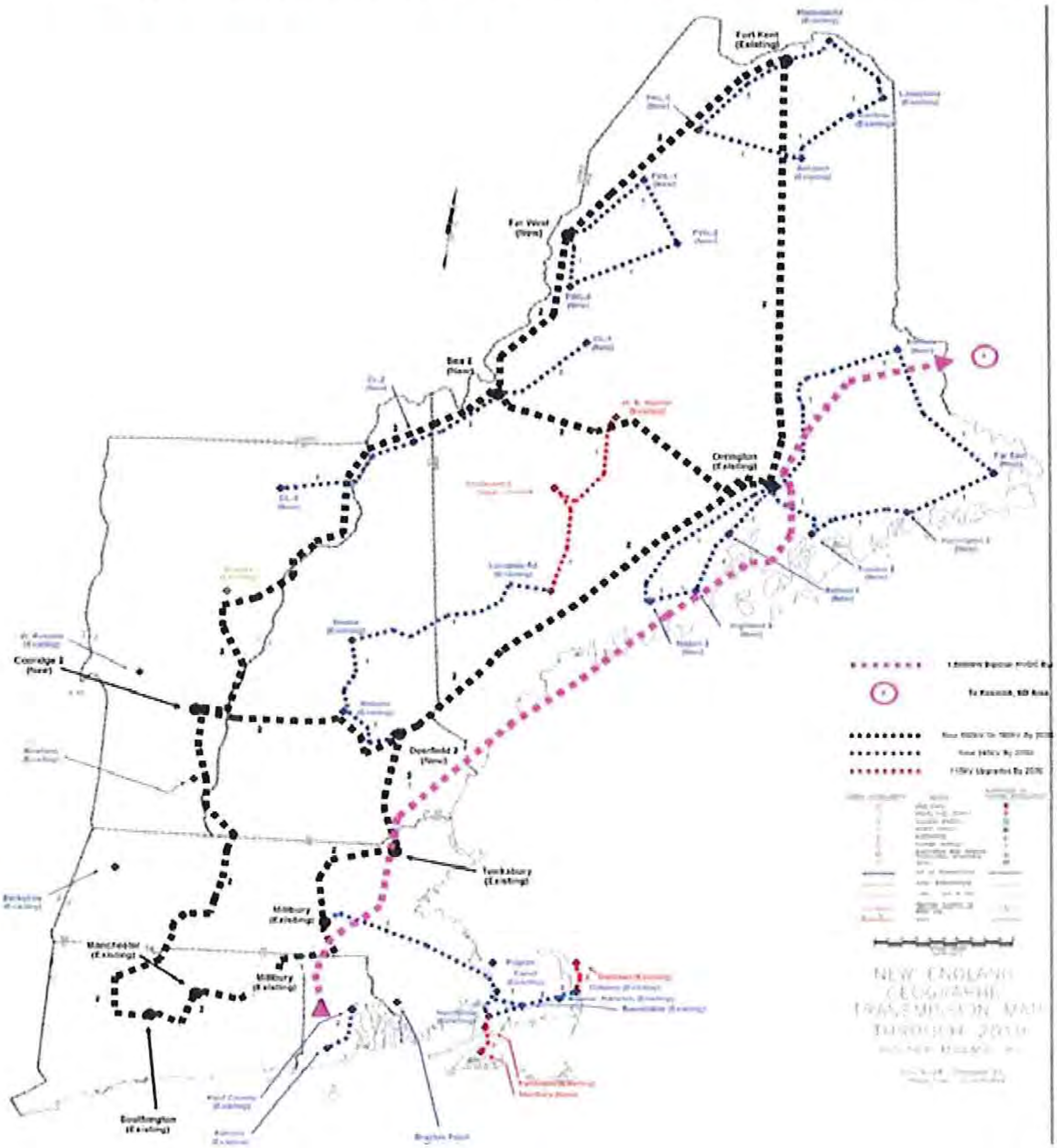


Figure 2–25 Governors' 8 GW overlay used for NEWIS 12 GW Wind Penetrations Scenarios

Figure 2–25 is a schematic of the 8 GW overlay. The 8 GW transmission overlay was used for the 12 GW nameplate capacity scenarios.

2.4 Analytical Methods

The primary objective of this study was to identify and quantify any system performance or operational problems with respect to load following, regulation, operation during low-load periods, etc. Three primary analytical methods were used to meet this objective; statistical analysis, hourly production simulation analysis, and reliability analysis. While the NEWIS tested the feasibility of wind integration under hypothetical future scenario analyses developed for the study, real-world operating and system performance conditions can vary significantly from these types of hypothesized scenarios.

Statistical analysis was used to quantify variability due to system load, as well as wind generation over multiple time frames (annual, seasonal, daily, hourly, and 10-minute). The power grid already has significant variability due to periodic and random changes to system load. Wind generation adds to that variability, and increases what must be accommodated by load following and regulation with other generation resources. The statistical analysis quantified the grid variability due to load alone over several time scales, as well as the changes in grid variability due to wind generation for each scenario. The statistical analysis also characterized the forecast errors for wind generation.

Production simulation analysis with General Electric's Multi-Area Production Simulation software (GE MAPS) was used to evaluate hour-by-hour grid operation of each scenario for 3 years with different wind and load profiles. The production simulation results quantified numerous impacts on grid operation including the primary targets of investigation:

- Amount of maneuverable generation on-line during a given hour, including its available ramp-up and ramp-down capability to deal with grid variability due to load and wind
- Effects of day-ahead wind forecast alternatives in unit commitment
- Changes in dispatch of conventional generation resources due to the addition of new renewable generation
- Changes in transmission path loadings

Other measures of system performance were also quantified, including:

- Changes in emissions (NOx, SOx, CO2) due to renewable generation
- Changes in energy costs and revenues associated with grid operation, and changes in net cost of energy
- Changes in use and economic value of energy storage resources

Reliability analysis involved loss of load expectation (LOLE) calculations for ISO-NE system using General Electric's Multi-Area Reliability Simulation program, (GE MARS). The analysis quantified the impact of wind generation on overall reliability measures, as well as the capacity values of the wind resources.

Impacts on system-level operating reserves were also analyzed using a variety of techniques including statistics and production simulation. This analysis quantified the effects of variability and uncertainty, and related that information to the system's increased need for operating reserves to maintain reliability and security.

The results from these analytical methods complemented each other, and provided a basis for developing observations, conclusions, and recommendations with respect to the successful integration of wind generation into the ISO-NE power grid.

3 Statistical Analysis and Characterization of Study Data

Wind generation is variable across time scales ranging from seconds to seasons, and cannot be perfectly forecast over any horizon. Because Balancing Area load also exhibits variability and uncertainty across many operational time frames, the impacts of wind generation on ISO-NE operations are a function of the degree to which this variability and uncertainty increases the overall variability and uncertainty of the net load.

The general purpose of the analysis in this section is to convey a familiarity with the chronological load and wind data that are the primary inputs to the technical analysis described in later sections. It is generally not possible to extract quantitative conclusions about operating impacts directly from statistics of wind and load data. While certain features may stand out from the perspective of system operations – such as lower net loads during off-peak hours – a range of other factors must be considered to determine the magnitude of the impact. Production simulations take a great number of these other factors into account as they seek to mimic the actual operation of the system against the array of operating constraints, and therefore are the better framework for drawing operational conclusions

Wind generation scenarios defined for the study are shown in Table 3–1. As described in Section 2.1, the scenarios were constructed by selecting grid cells from the NEWRAM. Individual cells were then grouped into "plants," for which chronological production data at ten-minute resolution over the calendar years 2004, 2005, and 2006 were extracted.

In the MAPS production simulations, individual plants were assigned to existing or planned network buses in the ISO-NE model. In this statistical analysis and characterization, the aggregate production, i.e. the total generation of all plants in each scenario, is analyzed.

As described in Section 2.2.1, ISO-NE load data at 10-minute resolution for the same calendar years as the wind production data was obtained. ISO-NE load data at 1-minute resolution for a different year was also used for analysis in the project, but is not reported on in this section. An extrapolation algorithm developed with guidance from ISO-NE staff was applied to the load data sets to make them representative of the future study year.

Table 3–1 Wind scenario description

Scenario	Installed Capacity (MW)
20% Queue + Best Sites Onshore	9,779
9% Full Queue	4,169
2.5% Partial Queue	1,140
20% Queue + Best Sites Offshore	8,294
20% Queue + Balance Case	8,798
20% Queue + Best Sites by State	10,235
20% Queue + Best Sites Maritimes	8,956
14% Queue + Best Sites Onshore	6,746
14% Queue + Best Sites Offshore	6,130
14% Queue + Balance Case	6,306
14% Queue + Best Sites by State	7,252
14% Queue + Best Sites Maritimes	6,394

Table 3–2 summarizes the ISO-NE load for 2004, 2005, and 2006 patterns – scaled for the study year – and hourly wind generation for each scenario. Load net of wind generation is summarized in Table 3–3. Of note in both tables are the aggregate annual energy statistics, the contribution of wind energy during peak load hours for each scenario, and the minimum net load. For one layout alternative at 20% penetration (the Best By State layout), the minimum net load is reduced from about 10 GW to less than 3 GW, or about 10% of peak load.

Operationally, the net of load and wind generation (i.e., the net load) will drive the decisions and algorithms for deployment of controllable resources (e.g. conventional generating units, energy transactions with neighboring markets and areas, and demand response). The net load analysis does not consider energy transactions with neighboring markets and systems, so the minimum hourly net load values for each scenario cannot be used directly to assess implications for the ISO-NE generation fleet. The price of the excess energy during these periods would be very low, and therefore presumably attractive to outside purchasers; energy sales could add significantly to the demand served by ISO-NE resources.

Table 3–4 documents the maximum and minimum net load hours by year. The minimum net load hour mentioned above (i.e. changing the minimum load from 10 GW to less than 3 GW) occurs for the "20% Queue + Best Sites by State" scenario for load and wind generation based on calendar year 2006 patterns. With patterns from the other calendar years, the minimum net load for this scenario is substantially higher (4997 MW for 2004, and 4228 MW for 2005). It is interesting to note that these absolute minimum net loads do not occur during the same hour of the year, or even in the same season (April for 2004, late October, but different days and hours for 2005 and 2006).

Table 3–2 Summary Statistics for Projected ISO-NE 2020 Load and Wind Generation Scenarios

Scenario	Maximum (MW)	Minimum (MW)	Average (MW)	Std. Deviation (MW)	Average Annual Energy (GWh)
Load	31,572	10,250	18,383	3,810	161,181
2.5% Partial Queue	1,055	0	422	266	3,697
9% Full Queue	3,824	2	1,416	898	12,414
14% Queue + Best Sites Onshore	6,364	2	2,380	1,555	20,872
14% Queue + Best Sites Offshore	5,665	4	2,333	1,403	20,459
14% Queue + Balance Case	5,825	9	2,331	1,384	20,440
14% Queue + Best Sites by State	6,731	7	2,355	1,484	20,649
14% Queue + Best Sites Maritimes	5,849	29	2,317	1,289	20,312
20% Queue + Best Sites Onshore	8,973	4	3,313	2,186	29,046
20% Queue + Best Sites Offshore	7,505	4	3,252	2,021	28,512
20% Queue + Balance Case	7,827	43	3,944	1,968	28,151
20% Queue + Best Sites by State	9,264	16	3,273	2,067	28,701
20% Queue + Best Sites Maritimes	8,198	57	3,322	1,872	29,125

Table 3–3 Load and Net Load Statistics over all 3 Years of Data

Scenario - Net Load	Maximum (MW)	Minimum (MW)	Average (MW)	Std. Deviation (MW)	Average Annual Energy (GWh)
Load	31,572	10,250	18,383	3,810	161,181
2.5% Partial Queue	31,141	9,749	17,961	3,804	157,484
9% Full Queue	30,617	7,712	16,967	3,863	148,766
14% Queue + Best Sites Onshore	30,333	5,865	16,002	4,044	140,309
14% Queue + Best Sites Offshore	30,404	5,875	16,049	3,971	140,722
14% Queue + Balance Case	30,235	5,748	16,052	3,942	140,740
14% Queue + Best Sites by State	30,454	5,267	16,028	4,003	140,532
14% Queue + Best Sites Maritimes	30,478	6,043	16,066	3,954	140,869
20% Queue + Best Sites Onshore	30,095	3,468	15,070	4,304	132,135
20% Queue + Best Sites Offshore	30,341	4,039	15,131	4,191	132,669
20% Queue + Balance Case	29,923	4,015	15,172	4,108	133,029
20% Queue + Best Sites by State	30,180	2,783	15,109	4,228	132,479
20% Queue + Best Sites Maritimes	30,284	4,130	15,061	4,143	132,055

Table 3–4 Maximum and Minimum Net Load by Pattern Year and Hour

	Maximum (MW)	Maximum Hour	Minimum (MW)	Minimum Hour
Scenario - Net Load - 2004 Patterns				
Load	31,572	8/31/04 16:00	12,075	6/1/04 5:00
2.5% Partial Queue	31,123	8/31/04 16:00	11,456	4/19/04 5:00
9% Full Queue	30,617	8/4/04 17:00	9,011	4/19/04 5:00
14% Queue + Best Sites Onshore	30,333	8/4/04 17:00	6,817	4/19/04 5:00
14% Queue + Best Sites Offshore	30,404	8/4/04 18:00	7,181	4/19/04 5:00
14% Queue + Balance Case	30,235	8/4/04 17:00	7,149	4/19/04 5:00
14% Queue + Best Sites by State	30,454	8/4/04 16:00	7,088	4/20/04 3:00
14% Queue + Best Sites Maritimes	30,478	8/4/04 17:00	7,376	4/20/04 3:00
20% Queue + Best Sites Onshore	30,095	8/4/04 17:00	4,438	4/20/04 3:00
20% Queue + Best Sites Offshore	30,341	8/4/04 18:00	5,349	4/19/04 5:00
20% Queue + Balance Case	29,923	8/4/04 17:00	5,343	4/19/04 5:00
20% Queue + Best Sites by State	30,180	8/4/04 16:00	4,997	4/20/04 3:00
20% Queue + Best Sites Maritimes	30,284	8/4/04 17:00	5,236	4/20/04 3:00
Scenario - Net Load - 2005 Patterns				
Load	31,545	7/29/05 18:00	10,885	6/1/05 7:00
2.5% Partial Queue	31,141	7/29/05 18:00	10,438	11/8/05 7:00
9% Full Queue	30,270	7/29/05 18:00	8,481	11/8/05 7:00
14% Queue + Best Sites Onshore	29,719	7/29/05 18:00	6,582	5/12/05 7:00
14% Queue + Best Sites Offshore	29,564	7/21/05 19:00	6,893	11/8/05 7:00
14% Queue + Balance Case	29,272	7/28/05 20:00	6,851	11/8/05 7:00
14% Queue + Best Sites by State	29,567	7/21/05 18:00	6,477	11/8/05 7:00
14% Queue + Best Sites Maritimes	30,178	7/29/05 18:00	6,441	11/8/05 6:00
20% Queue + Best Sites Onshore	29,542	7/28/05 20:00	4,334	4/3/05 6:00
20% Queue + Best Sites Offshore	29,313	7/21/05 16:00	5,130	11/8/05 8:00
20% Queue + Balance Case	28,990	7/28/05 20:00	5,195	4/3/05 6:00
20% Queue + Best Sites by State	29,024	7/21/05 18:00	4,228	10/25/05 8:00
20% Queue + Best Sites Maritimes	30,054	7/29/05 18:00	4,133	11/8/05 6:00

	Maximum (MW)	Maximum Hour	Minimum (MW)	Minimum Hour
Scenario - Net Load - 2006 Patterns				
Load	31,557	7/29/06 16:00	10,250	4/12/06 7:00
2.5% Partial Queue	30,785	7/29/06 19:00	9,749	4/13/06 6:00
9% Full Queue	30,107	7/30/06 17:00	7,712	4/13/06 6:00
14% Queue + Best Sites Onshore	29,914	7/30/06 17:00	5,865	4/13/06 6:00
14% Queue + Best Sites Offshore	30,103	7/30/06 17:00	5,875	4/13/06 6:00
14% Queue + Balance Case	29,890	7/30/06 17:00	5,748	4/13/06 6:00
14% Queue + Best Sites by State	29,828	7/30/06 17:00	5,267	10/29/06 6:00
14% Queue + Best Sites Maritimes	29,212	7/13/06 20:00	6,043	4/13/06 6:00
20% Queue + Best Sites Onshore	29,710	7/30/06 17:00	3,468	10/21/06 7:00
20% Queue + Best Sites Offshore	30,102	7/30/06 17:00	4,039	4/13/06 6:00
20% Queue + Balance Case	29,675	7/30/06 17:00	4,015	4/13/06 6:00
20% Queue + Best Sites by State	29,738	7/30/06 17:00	2,783	10/29/06 6:00
20% Queue + Best Sites Maritimes	28,821	7/13/06 18:00	4,130	4/13/06 6:00

Maximum net loads are also of interest. Looking only at the single hour maximum net load hour, it can be seen from the tables that wind generation in all of the scenarios reduces the ISO-NE peak load. The amount of this reduction varies by scenario and year, as would be expected from the differing geographic makeup of each scenario and the variability between years in terms of both load and wind resources. Scenarios with a greater proportion of offshore wind resources, for example, have a higher probability of significant production during the single peak demand hour due to the nature and timing of the sea breezes.

It may be tempting to draw some conclusions about the scenario capacity values from the table. However, the focus on a single hour is not appropriate and is potentially misleading. The capacity value analysis described later in the report will consider not just these single hours, but all hours of an annual period along with the important system risks to determine wind generation capacity contributions with a much higher degree of confidence. The rigorous analytical methodology used in this study to determine the capacity value of each wind scenario is much less prone to being influenced by a single hour of the chronological data.

The initial part of this section focuses on the variability of wind generation as defined by the study scenarios and how it combines with the inherent variability of ISO-NE load. The analysis first looks at hourly data over the entire three years of the available wind and load data. Variability and uncertainty are then examined with the 10-minute interval data. Finally, the uncertainty and error characteristics of various forecasts available for the chronological wind production data are analyzed including the day-ahead and 4-hour ahead forecasts that are part of the NEWRAM. Other techniques important to the analysis presented later in the report, such as persistence forecasts, are also examined.

The analysis here is conducted on an aggregate basis for the entire footprint; that is, the total generation for each time interval (10-minute, 1-hour, as appropriate) is considered, independent of where the individual virtual plants may be located. Differences stemming from alternate layouts of wind generation for scenarios of similar penetration are used to compare locational effects. The transmission infrastructure assumed for the study was not a factor in this analysis; the views of the data here assume a zero-impedance "copper sheet" network for transporting energy from sources to loads.

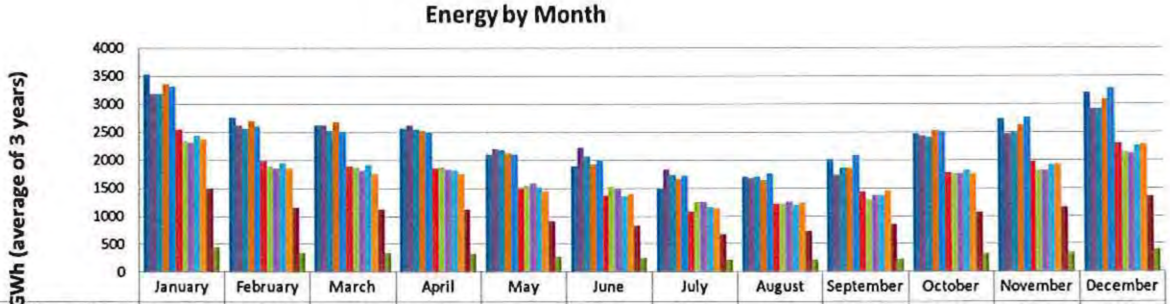
3.1 Wind Generation Variability

The time horizons for which wind generation variability is important for power system operations range from tens of seconds to seasons. Over shorter horizons, the variability appears as almost random due to the extremely large number of factors that can influence production over this time frame. Over longer horizons, such as weeks or seasons, patterns reflecting the underlying meteorological drivers for wind generation can usually be discerned. Over longer time scales such as years, varying production is driven by even larger meteorological patterns that were first identified a few decades ago, e.g. the El Nino/La Nina cycle in the Pacific, and closer to New England, the North Atlantic Oscillation.

3.1.1 Variability – Energy Production

The energy delivery by month for all wind generation scenarios is shown in Figure 3–1. The monthly values reflect the average of all three years of production data in the NEWRAM dataset. The bias toward production in the winter months is clearly seen, as well as the minimum production over the summer (i.e. peak load) months.

Another view of the same data is found in Figure 3–2, with the energy production averaged by seasons rather than individual months.



	January	February	March	April	May	June	July	August	September	October	November	December
20% Queue + Best Sites Onshore	3529	2760	2620	2561	2103	1882	1493	1693	1998	2462	2743	3202
20% Queue + Best Sites Offshore	3174	2616	2617	2628	2196	2215	1835	1675	1743	2431	2462	2919
20% Queue + Balanced Case	3174	2569	2534	2544	2175	2069	1731	1703	1845	2401	2491	2916
20% Queue + Best Sites by State	3354	2696	2674	2532	2119	1932	1652	1645	1850	2531	2622	3094
20% Queue + Best Sites Maritimes	3321	2605	2510	2483	2098	1992	1715	1763	2090	2515	2764	3268
14% Queue + Best Sites Onshore	2543	1987	1896	1845	1508	1361	1071	1213	1419	1767	1964	2298
14% Queue + Best Sites Offshore	2326	1888	1863	1869	1550	1524	1252	1205	1294	1748	1808	2134
14% Queue + Balanced Case	2306	1857	1819	1837	1573	1480	1248	1255	1370	1747	1820	2129
14% Queue + Best Sites by State	2435	1941	1899	1817	1512	1356	1154	1198	1365	1816	1908	2247
14% Queue + Best Sites Maritimes	2365	1843	1761	1752	1449	1379	1140	1225	1449	1749	1925	2275
9% Full Queue	1478	1164	1112	1110	901	831	666	736	845	1065	1156	1352
2.5% Partial Queue	434	349	345	334	271	246	208	212	237	327	337	397

Figure 3–1 Average monthly energy delivery by wind generation scenario

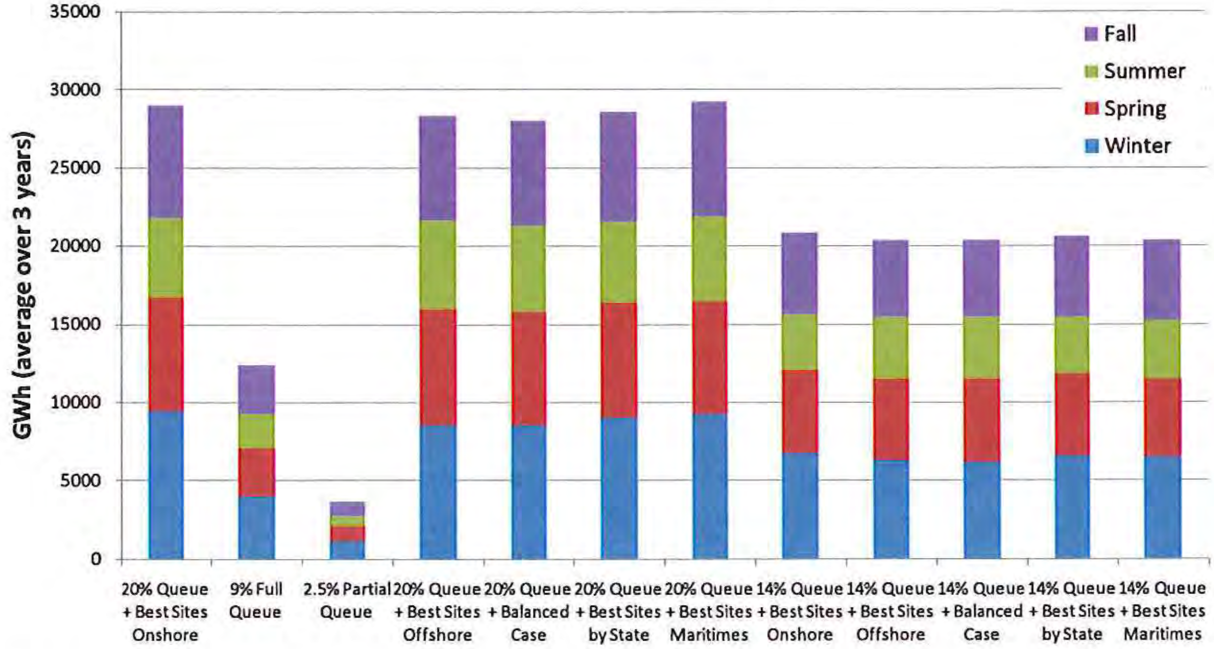
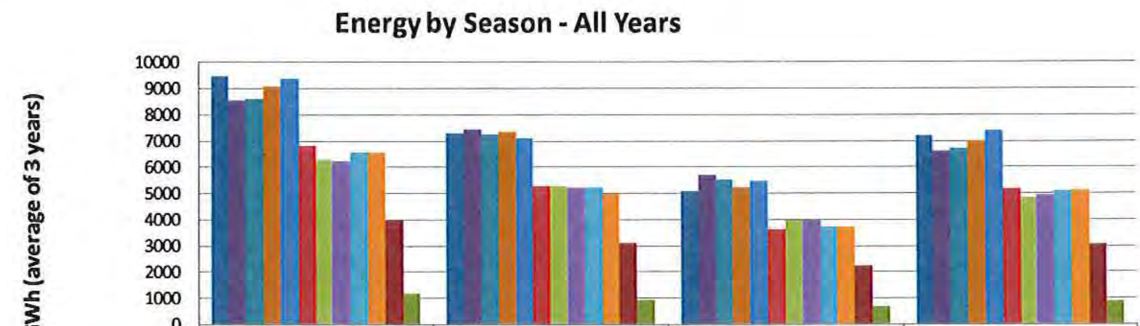


Figure 3–2 Average energy delivery by season for each wind generation scenario

On a seasonal basis, and averaged over all three years of data, the highest production of the winter months is still evident (Figure 3–3). Seasonal contributions as a percentage of the total are shown for all scenarios in Figure 3–4.



	Winter	Spring	Summer	Fall
20% Queue + Best Sites Onshore	9474	7284	5068	7203
20% Queue + Best Sites Offshore	8556	7441	5725	6636
20% Queue + Balanced Case	8580	7253	5504	6736
20% Queue + Best Sites by State	9070	7325	5229	7003
20% Queue + Best Sites Maritimes	9353	7092	5470	7369
14% Queue + Best Sites Onshore	6805	5249	3645	5150
14% Queue + Best Sites Offshore	6268	5281	3980	4850
14% Queue + Balanced Case	6255	5229	3983	4937
14% Queue + Best Sites by State	6590	5228	3708	5089
14% Queue + Best Sites Maritimes	6565	4962	3744	5123
9% Full Queue	3986	3123	2232	3066
2.5% Partial Queue	1167	950	667	901

Figure 3–3 Wind energy production by season and scenario, averaged over 3 years

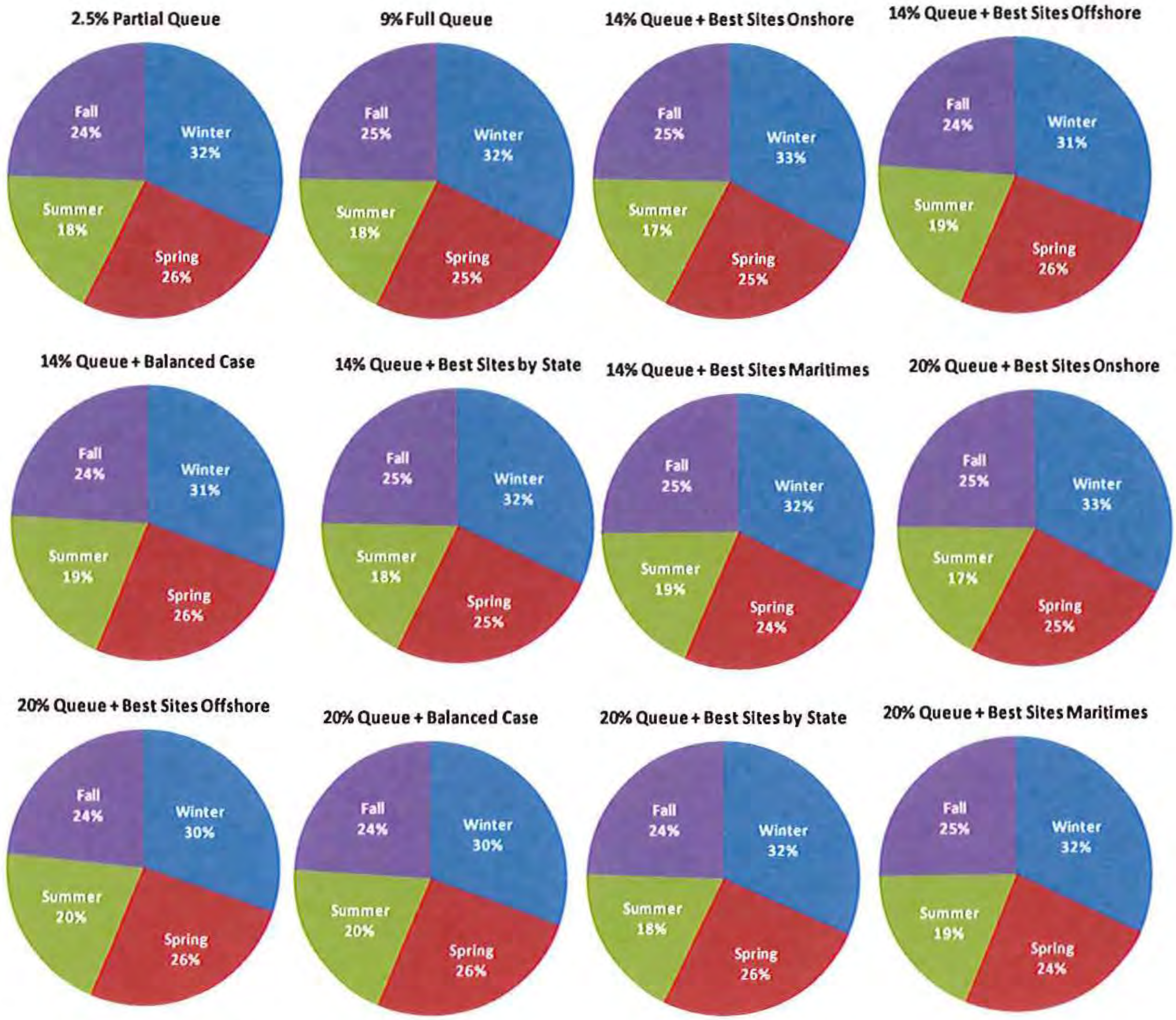


Figure 3–4 Seasonal energy contribution for wind generation scenarios

In general, the scenarios are quite similar with respect to monthly and seasonal energy production characteristics. Highest production occurs during the winter season, with the lowest production in summer. The composite nature of each scenario (different mixture of on- and off-shore plants, differing geographic characteristics, etc.) and averaging production over three years of annual hourly data are likely responsible for attenuating the contrasts regarding energy production. All of the large scenarios (14% and 20% energy) have the 9% Full Queue scenario in common, which is another reason for the similarities.

Examination of the wind production data on a year-by-year basis reveals some inter-annual variability. Figure 3–5 shows the variation in annual energy for each scenario for each of the three years of wind data. The "20% Queue + Best Sites Onshore" and "20% Queue +Best Sites Maritimes" scenarios show the most annual variability. Figure 3–6 shows the seasonal variation by year for these two scenarios, and shows that most of the annual variability occurs in the winter and fall seasons.

It should also be noted that the three-year record is likely insufficient for completely understanding variations in energy production between years. The large-scale weather drivers mentioned previously can be periods of many years to decades, so a sample of three years would not paint a complete picture of the expected inter-annual variability. The large scale climatological phenomena mentioned earlier have periods of several years to a decade, and sunspot cycles, also considered to influence climate, have 7 and 11 years periods. It has been speculated that at least ten years of data might be needed to develop a high degree of confidence in the long-term behavior.

Figure 3–7 through Figure 3–9 detail the energy by season and scenario for each year of the dataset.

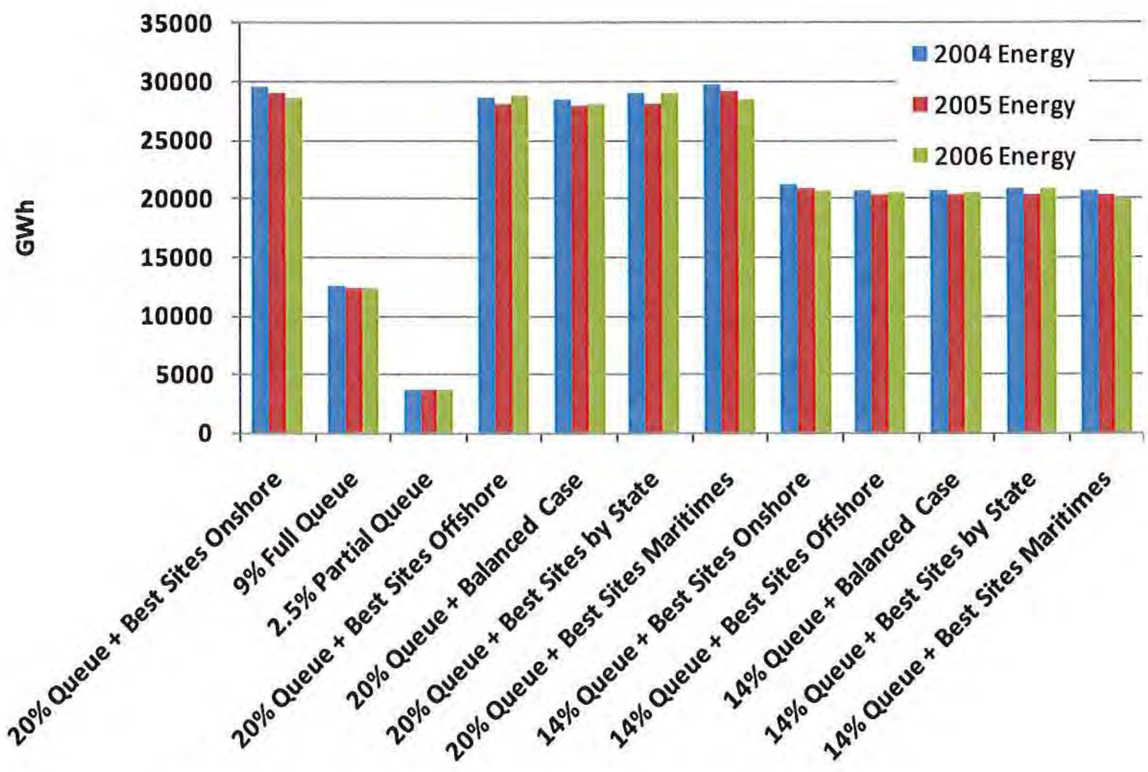


Figure 3–5 Energy delivery by year for each scenario

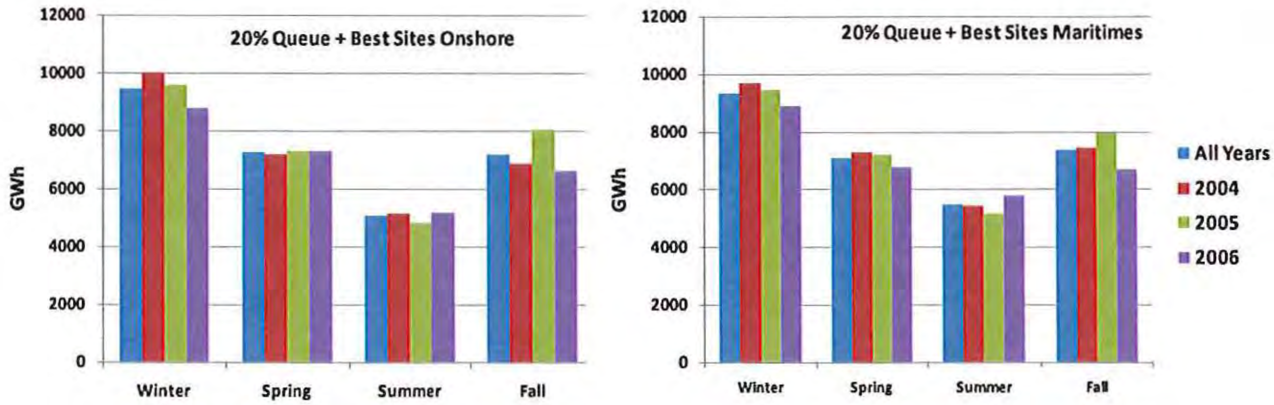
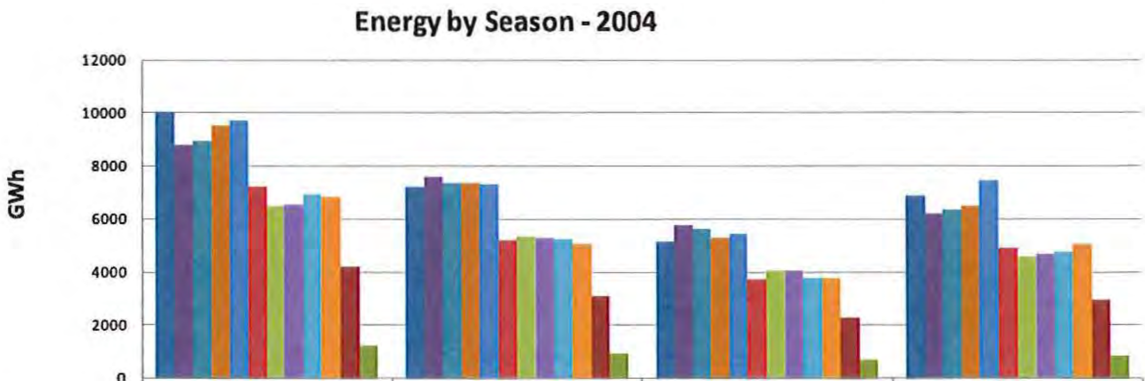
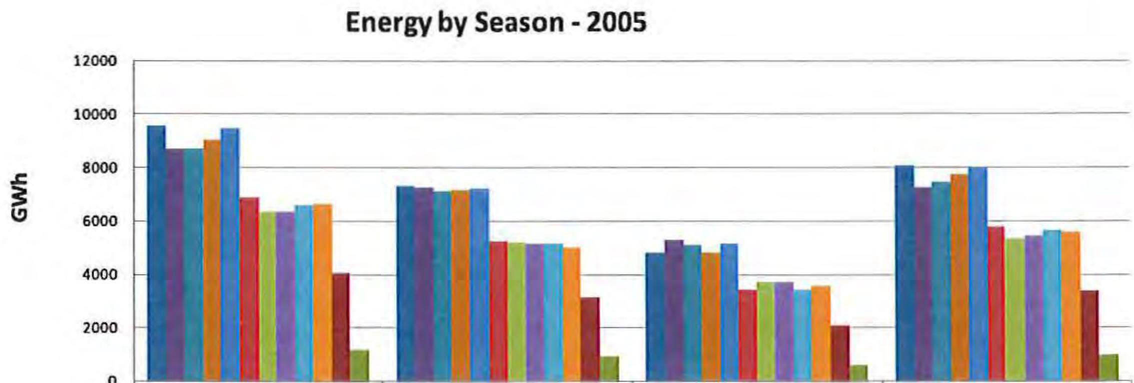


Figure 3–6 Seasonal inter-annual variability for 20% Best Sites Onshore and 20% Best Sites Maritimes scenarios



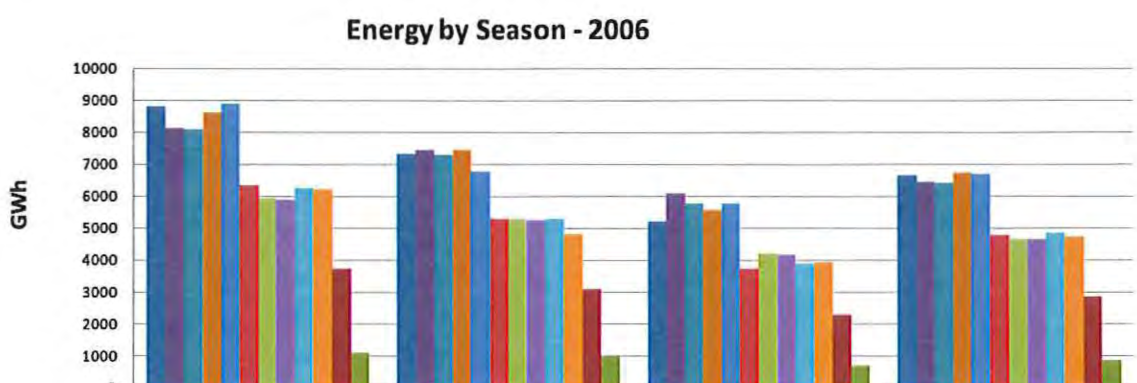
	Winter	Spring	Summer	Fall
20% Queue + Best Sites Onshore	10038	7200	5158	6885
20% Queue + Best Sites Offshore	8815	7613	5785	6187
20% Queue + Balanced Case	8953	7345	5612	6356
20% Queue + Best Sites by State	9536	7366	5295	6518
20% Queue + Best Sites Maritimes	9693	7288	5442	7435
14% Queue + Best Sites Onshore	7218	5185	3728	4915
14% Queue + Best Sites Offshore	6500	5358	4034	4561
14% Queue + Balanced Case	6532	5280	4066	4683
14% Queue + Best Sites by State	6941	5239	3783	4761
14% Queue + Best Sites Maritimes	6822	5072	3755	5067
9% Full Queue	4191	3109	2282	2930
2.5% Partial Queue	1230	942	695	846

Figure 3–7 2004 energy by season



	Winter	Spring	Summer	Fall
20% Queue + Best Sites Onshore	9576	7325	4833	8076
20% Queue + Best Sites Offshore	8720	7268	5303	7274
20% Queue + Balanced Case	8695	7131	5131	7460
20% Queue + Best Sites by State	9053	7159	4820	7761
20% Queue + Best Sites Maritimes	9474	7203	5179	7981
14% Queue + Best Sites Onshore	6880	5271	3454	5767
14% Queue + Best Sites Offshore	6372	5206	3706	5329
14% Queue + Balanced Case	6331	5165	3703	5465
14% Queue + Best Sites by State	6582	5144	3428	5640
14% Queue + Best Sites Maritimes	6641	5014	3552	5567
9% Full Queue	4034	3142	2100	3393
2.5% Partial Queue	1165	925	590	992

Figure 3–8 2005 energy by season



	Winter	Spring	Summer	Fall
20% Queue + Best Sites Onshore	8808	7327	5212	6648
20% Queue + Best Sites Offshore	8133	7442	6088	6448
20% Queue + Balanced Case	8093	7281	5768	6393
20% Queue + Best Sites by State	8622	7451	5572	6730
20% Queue + Best Sites Maritimes	8891	6783	5790	6689
14% Queue + Best Sites Onshore	6316	5290	3751	4769
14% Queue + Best Sites Offshore	5932	5279	4201	4660
14% Queue + Balanced Case	5901	5241	4180	4662
14% Queue + Best Sites by State	6248	5300	3914	4867
14% Queue + Best Sites Maritimes	6231	4800	3924	4735
9% Full Queue	3732	3119	2314	2874
2.5% Partial Queue	1106	984	715	864

Figure 3–9 2006 energy by season

3.1.2 Capacity Factor

Average capacity factor over the three years of data for each scenario is shown in Figure 3–10. The scenarios with substantial offshore wind generation (i.e. "Best Sites Offshore") - at both the 20% and 14% penetration levels exhibit the highest capacity factors of approximately 40% and 38%, respectively. The lowest capacity factors are associated with the "Best Sites by State" scenarios, where wind resource quality was de-emphasized in favor of a preferred geographic distribution of wind generation. Even so, the average capacity factors are still above 30%.

The aggregate capacity factors for the ISO-NE study scenarios are typical of the expectations for the wind resource in the northeastern U.S. The source data for NEWRAM covers the entire eastern U.S., and shows capacity factors of 40 to 50% for the best wind resources in the Great Plains. Capacity factors for sites in this database generally decline as one moves east.

The differences in annual capacity factors between years for all scenarios are relatively small, varying by less than 2% from the three-year average.

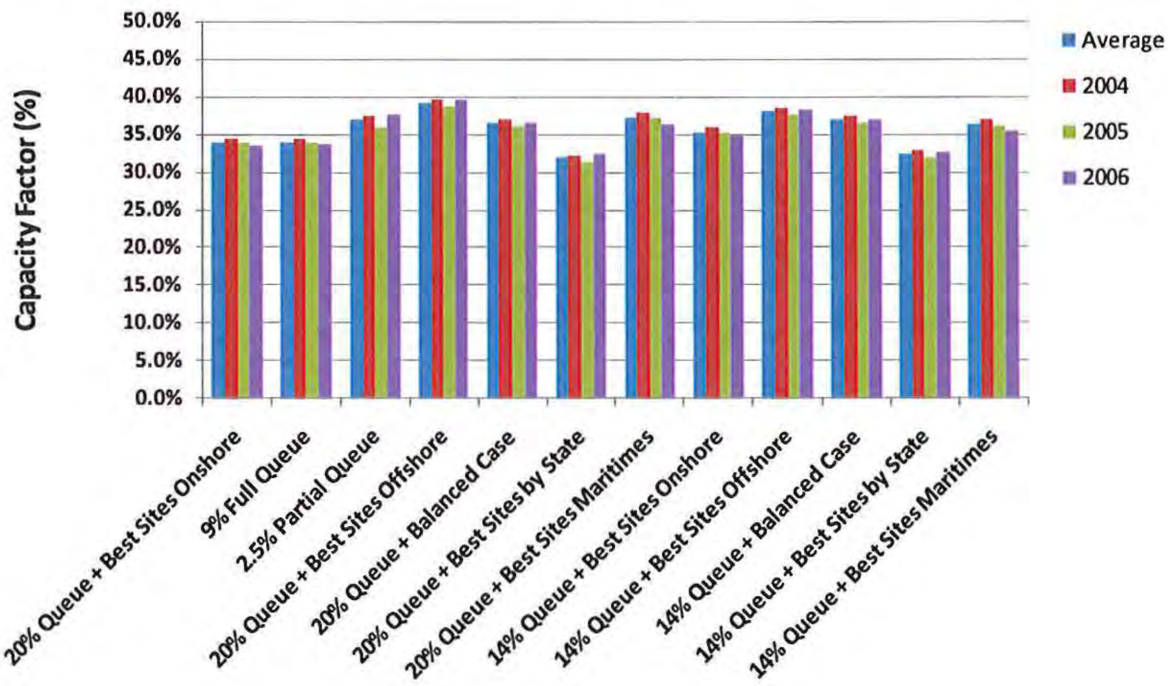


Figure 3–10 Average annual capacity factor for each scenario, and by year

Capacity factor by season averaged over all three years for each scenario are shown in Figure 3–11. High capacity factors in the winter season and low capacity factors in summer are the obvious features. Winter capacity factors ranged from 40% to 50% for all of the scenarios, with the scenarios containing significant offshore wind exhibiting the highest. Summer capacity factors fall below 30%, again, except for those scenarios with significant offshore resources.

Figure 3–11 also shows the capacity factor breakdown between on-peak and off-peak hours (peak load hours are defined for each season as Hour 11 through Hour 19). For all scenarios, in all seasons, the on-peak capacity factor exceeds that in the off-peak hours. This result is somewhat surprising relative to other integration studies and even the measured characteristics of many operating wind projects, where wind generation exhibits at least some negative correlation to average daily load patterns.

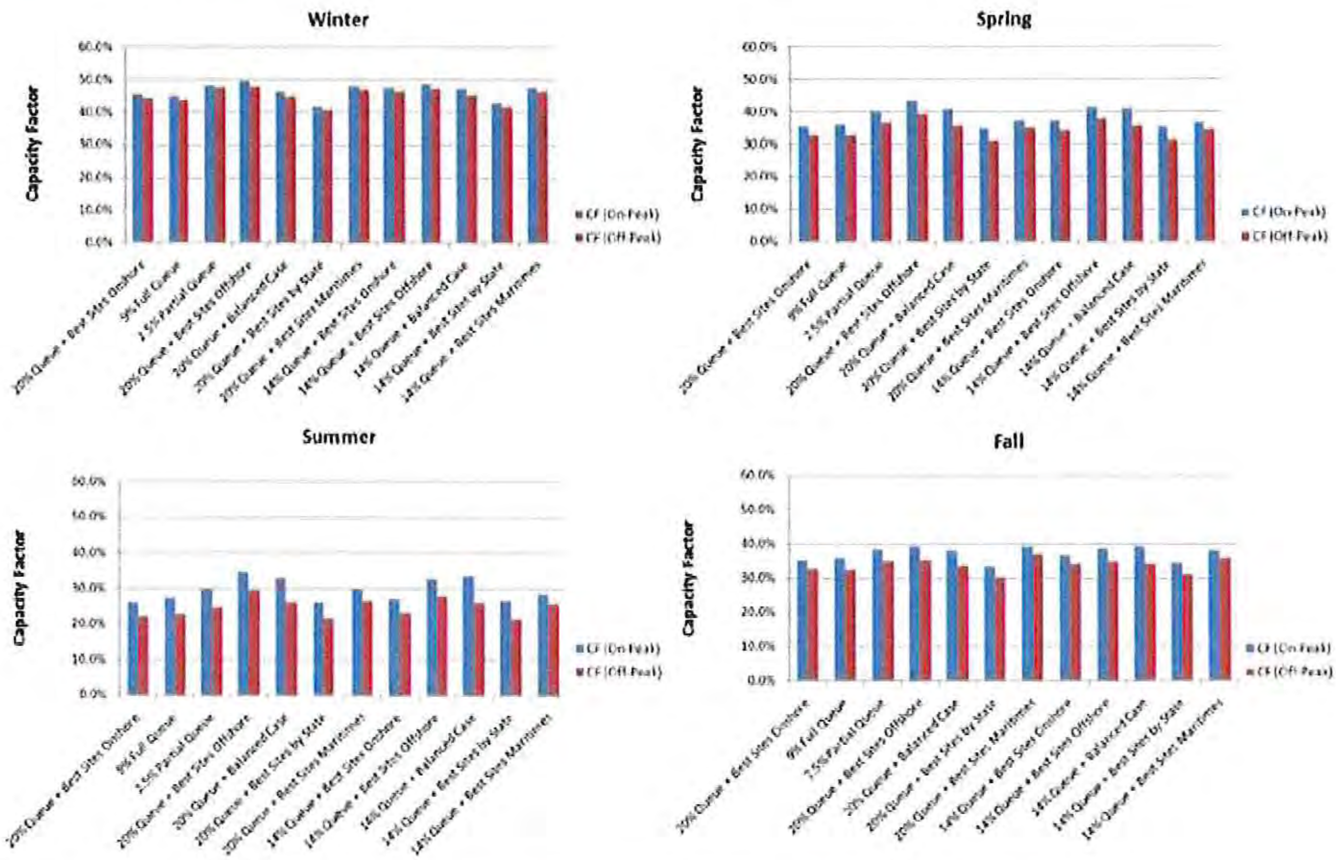


Figure 3–11 Capacity factor by (on-peak and off-peak) for each scenario (average of three years)

3.1.3 Hourly Variability – Diurnal Characteristics

The large-scale meteorological phenomena that drive wind generation exhibit cycles that are non-integer multiples of 24 hour days. In addition, other wind generation drivers, such as sea breezes or atmospheric mixing can correspond to diurnal cycles in certain seasons.

Averaging by hour of the day over an extended period such as a season can help reveal these patterns. Figure 3–12 through Figure 3–15 show the average daily patterns of wind generation for each scenario by season.

The winter pattern shown in Figure 3–12 is marked by two maxima in wind generation, one corresponding to the morning load pickup period, the other the late afternoon/early evening peak period. The pattern is evident in all scenarios. This would appear to be very desirable from a power system operations perspective. It should be remembered, however, that the patterns presented have been heavily smoothed by averaging over a large number of hours (over 1000), and the 3 year dataset available for analysis may not be indicative of behavior over longer record lengths, which could reveal larger meteorological patterns.

The average spring pattern (Figure 3–13) is less variable than that for winter, but also exhibits an increasing trend later in the day toward peak load hours. Production drops over the nighttime hours, and the timing of the increase over the day may or may not correspond to the morning load pickup.

The summer pattern in Figure 3–14 also shows declining levels of wind generation over the early morning until around or just after sunrise. Again, the timing of the pickup in wind generation in the average pattern would appear to be potentially helpful with morning load pickup, but the earlier qualifications also apply here.

The fall pattern (Figure 3–15) is similar to that in springtime, more constant than winter or summer, with a larger late-day peak.

Duration curves for each wind generation scenario using all three years of hourly data are shown in Figure 3–16.

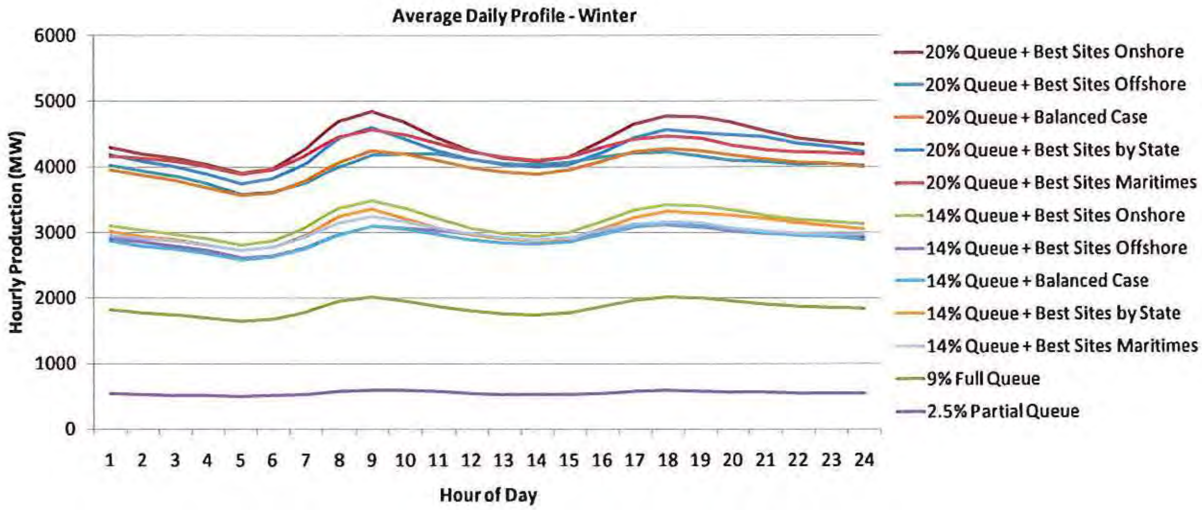


Figure 3–12 Average daily wind generation profile for winter (3 years of data)

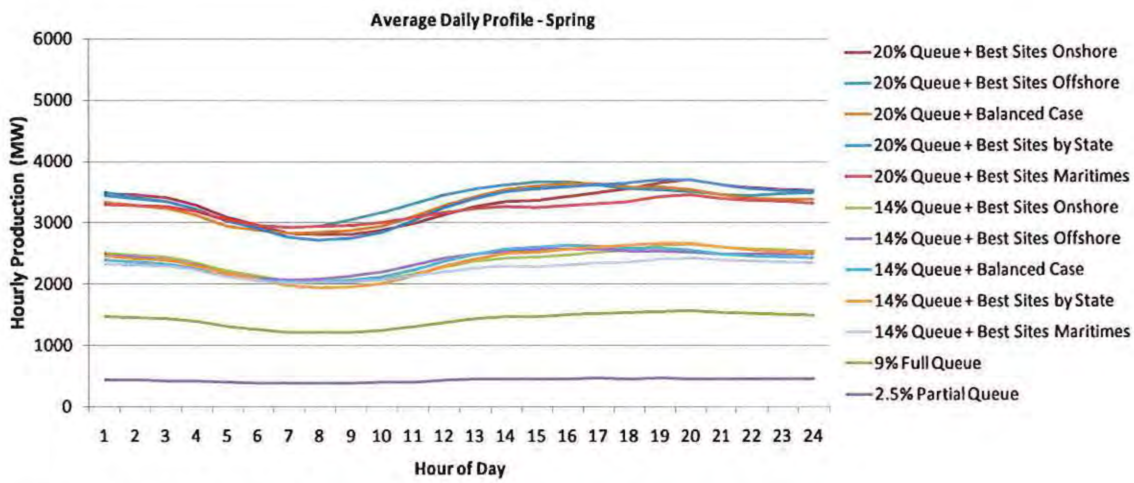


Figure 3–13 Average daily wind generation profile for spring (3 years of data)

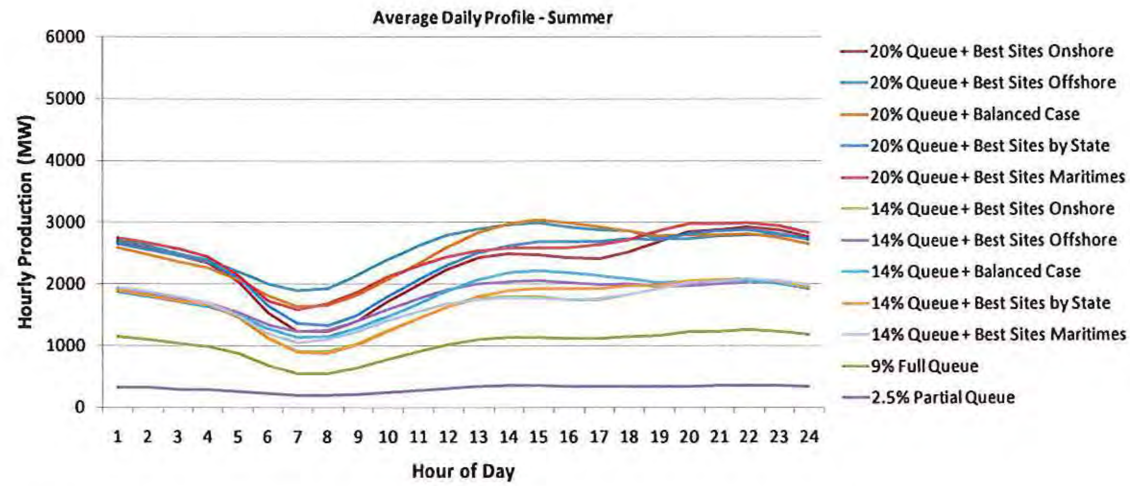


Figure 3–14 Average daily wind generation profile for summer (3 years of data)

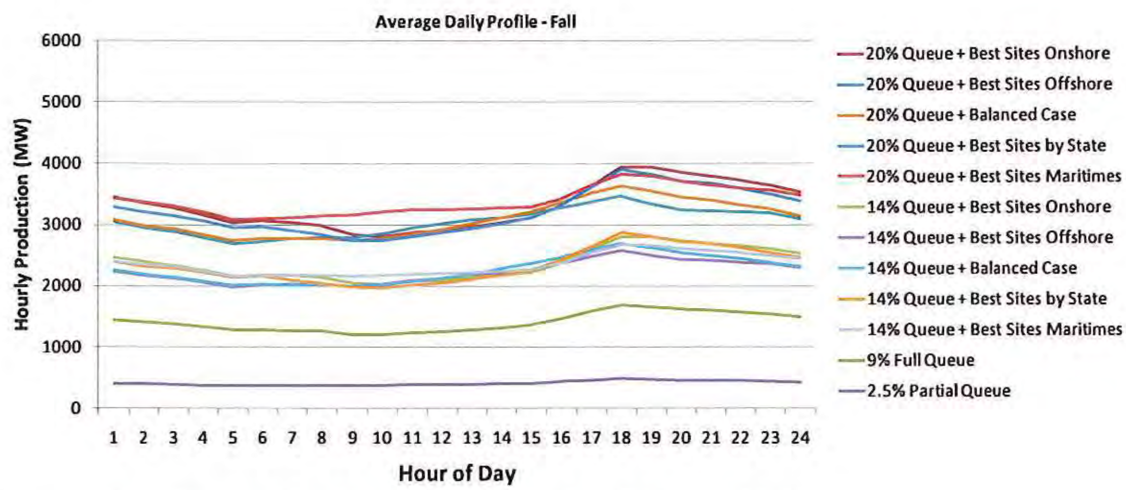


Figure 3–15 Average daily wind generation profile for fall (3 years of data)

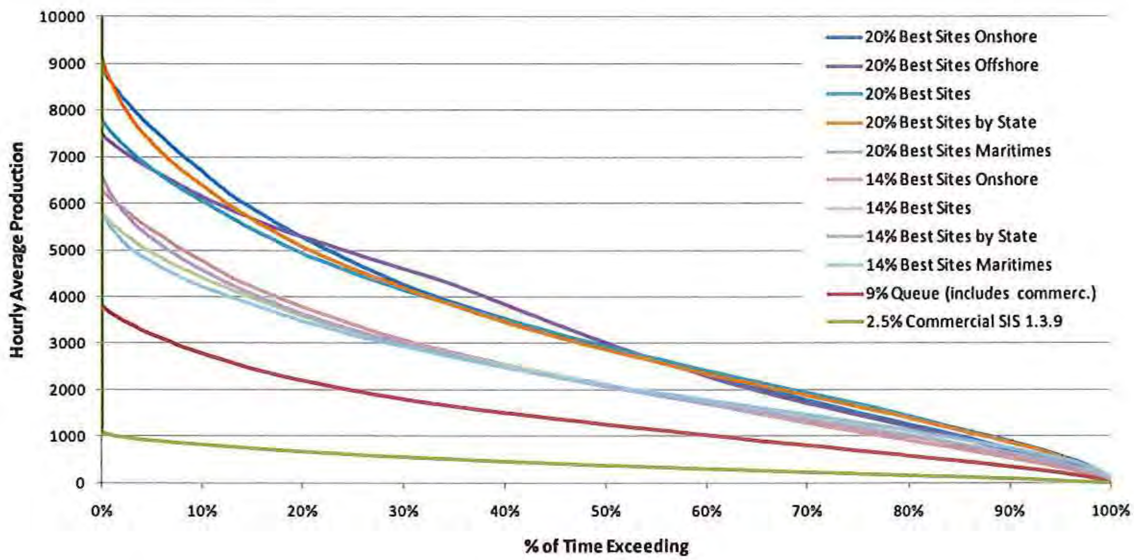


Figure 3–16 Hourly duration curves for each wind generation scenario

Increasing granularity helps to reveal more details about the behavior of the aggregate wind production in each scenario. Figure 3–17 through Figure 3–21 below show the hourly average daily production by month for each scenario, along with the maximum and minimum values for each hour. The data is based on all three years of data in the NEWRAM, or over 26,000 chronological hours of data.

The trends noted previously are again evident here, with highest production during the winter and lowest in summer. The charts also show a diurnal pattern in the summer, but not in winter. During the spring and fall seasons, the pattern appears transitional, with more diurnal behavior in the months nearer to summer, and less in those adjacent to the winter season.

For all scenarios, periods of zero or very low production occur in all months of the year. Hours of maximum production, near the installed nameplate capacity of the wind generation in each scenario, occur in all seasons except summer.

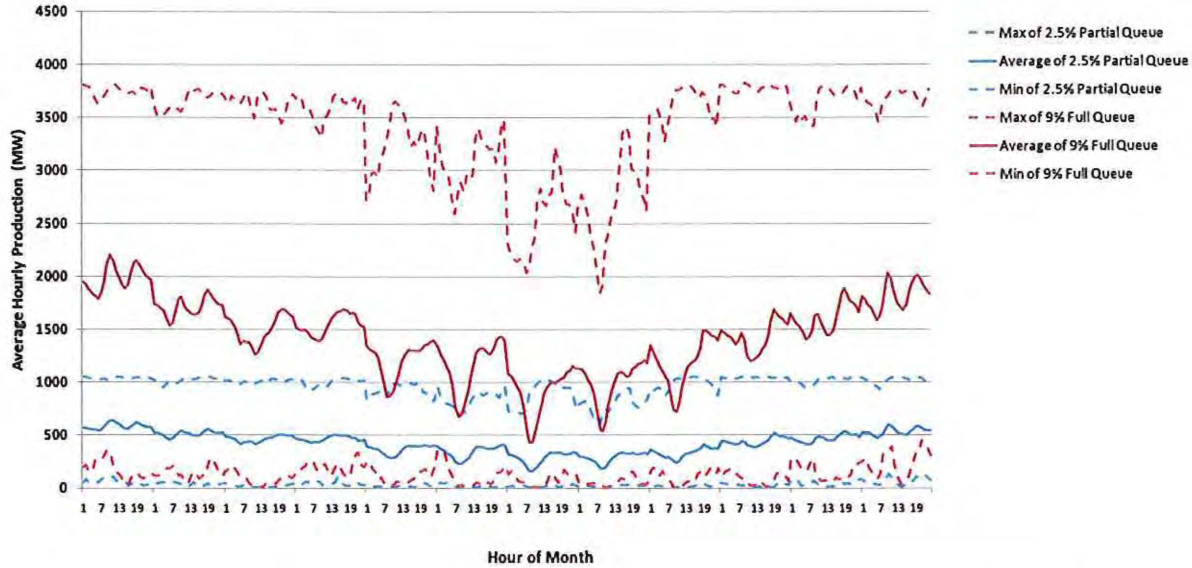


Figure 3–17 Average daily patterns by month for low penetration scenarios; maximum and minimum values indicated by dashed lines.

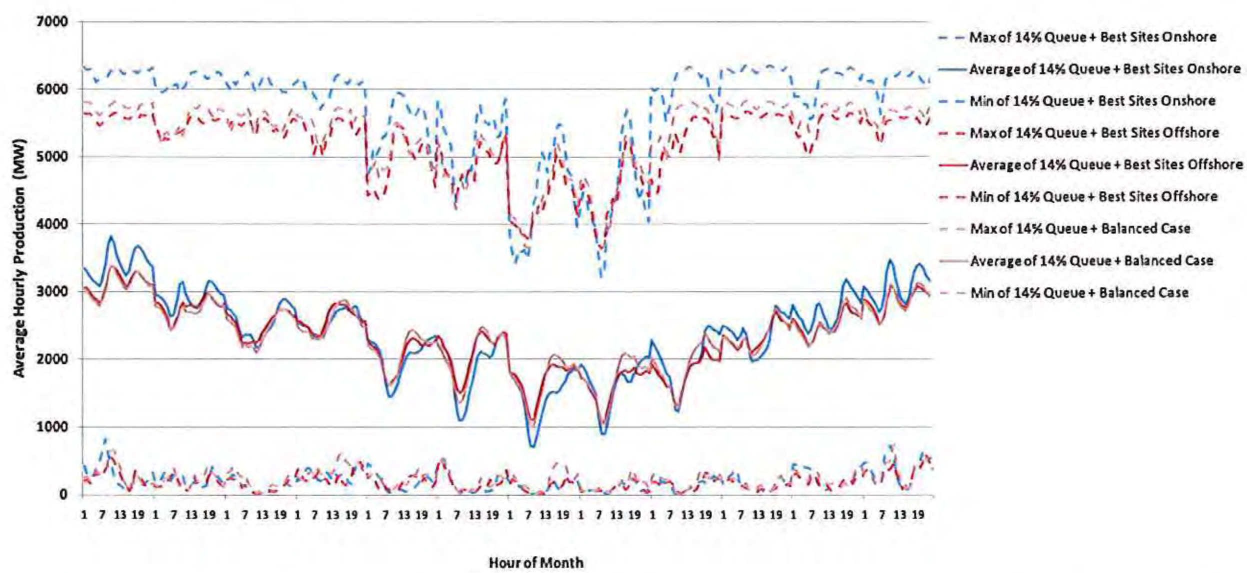


Figure 3–18 Average daily patterns by month for three 14% scenarios; maximum and minimum values indicated by dashed lines.

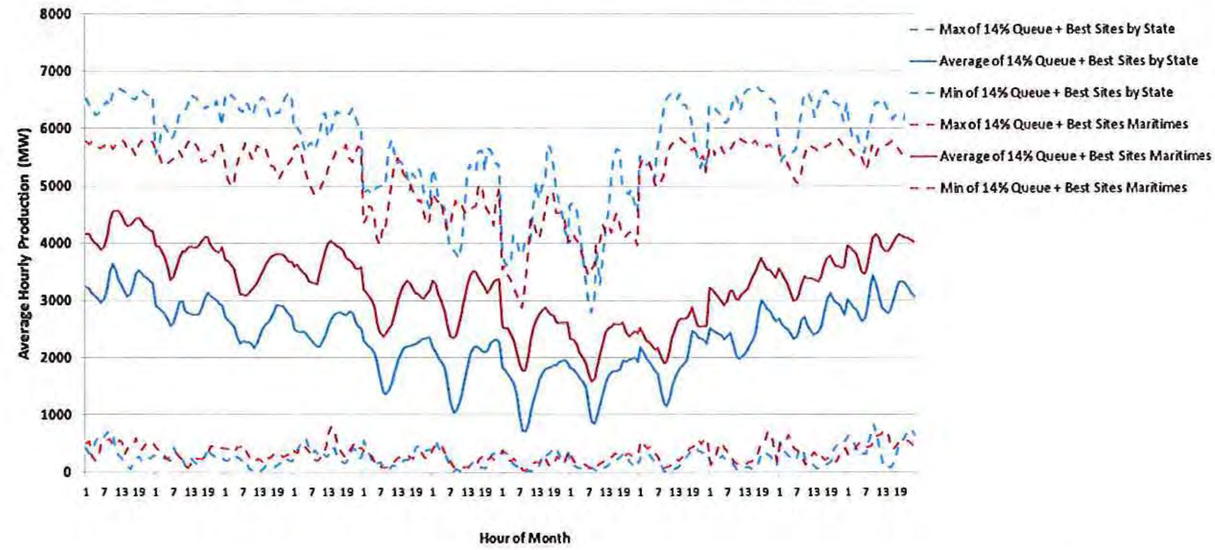


Figure 3–19 Average daily patterns by month for two 14% scenarios; maximum and minimum values indicated by dashed lines.

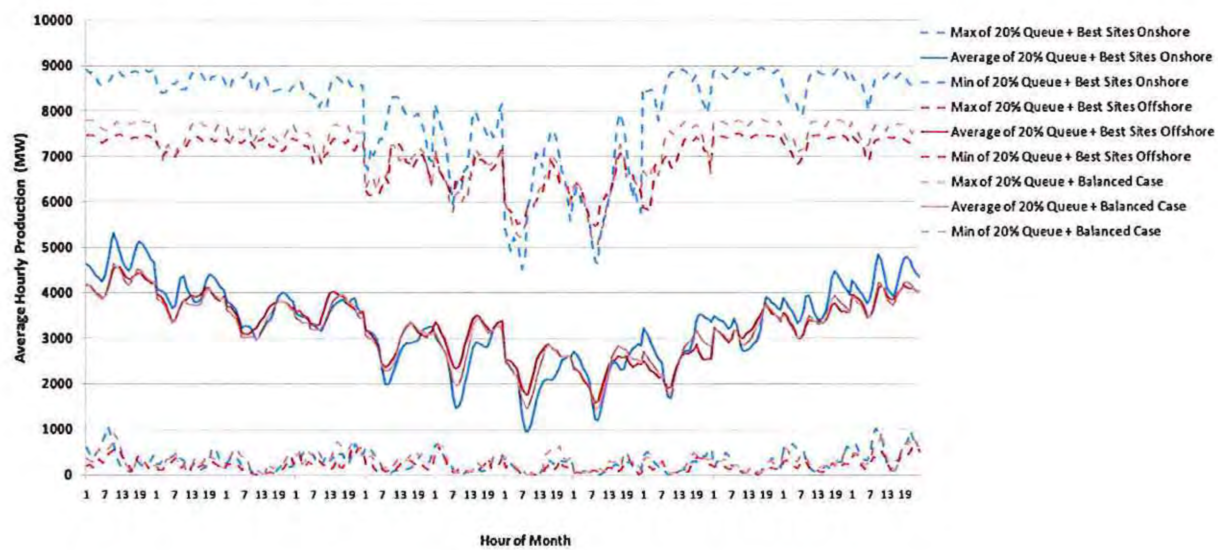


Figure 3–20 Average daily patterns by month for three 20% scenarios; maximum and minimum values indicated by dashed lines.

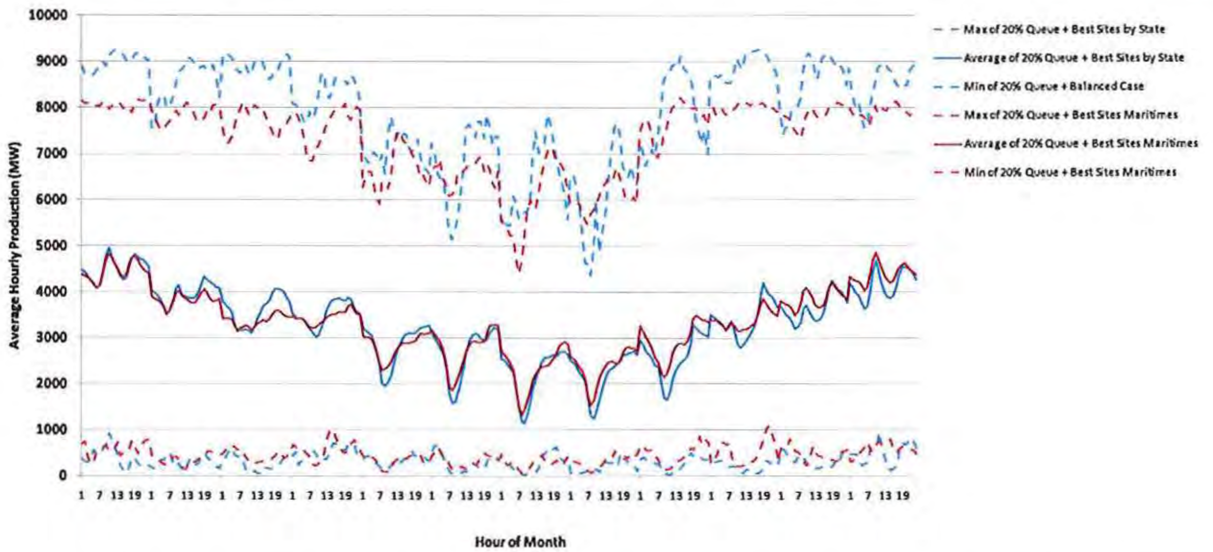


Figure 3–21 **Average daily patterns by month for two 20% scenarios; maximum and minimum values indicated by dashed lines.**

3.1.4 Daily Variability – Load net of Wind Generation

The average daily patterns of wind generation for each season are interesting and can, to the knowledgeable eye, help reveal some of the driving forces behind regional wind generation. Operationally, though, how wind generation patterns combine with those of load is of much more interest. Figure 3–22 though Figure 3–25 combine the daily wind generation patterns above with average ISO-NE 2020 load for each hour and season. Load and net load duration curves for the three years of data are found in Figure 3–26.

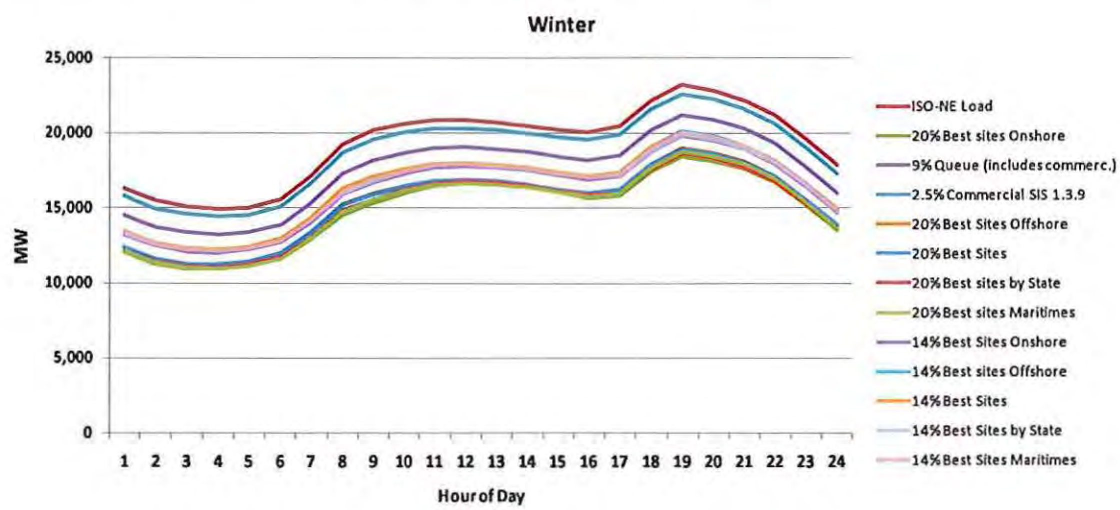


Figure 3–22 **Average daily net load profiles for each scenario, winter season**

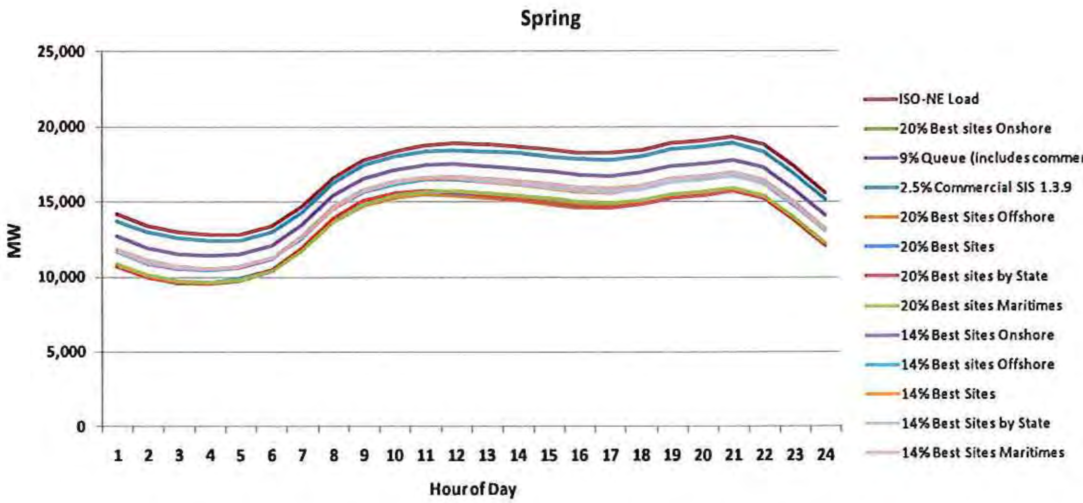


Figure 3–23 Average daily net load profiles for each scenario, spring season

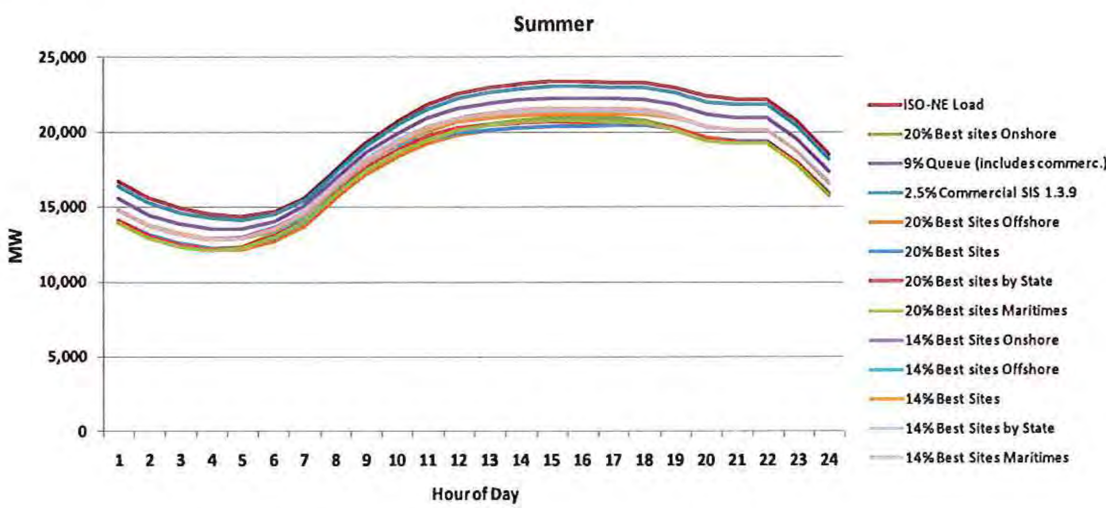


Figure 3–24 Average daily net load profiles for each scenario, summer season

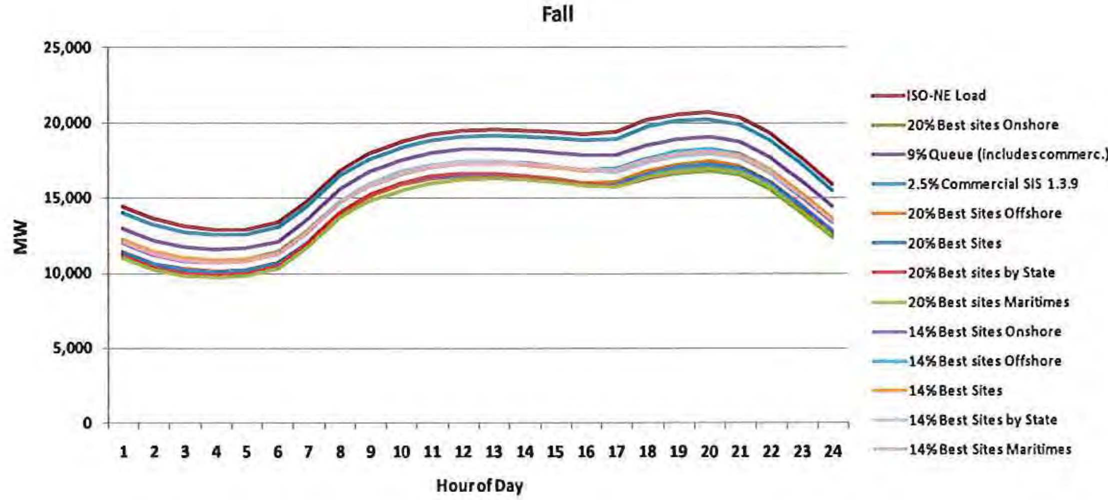


Figure 3–25 Average daily net load profiles for each scenario, fall season

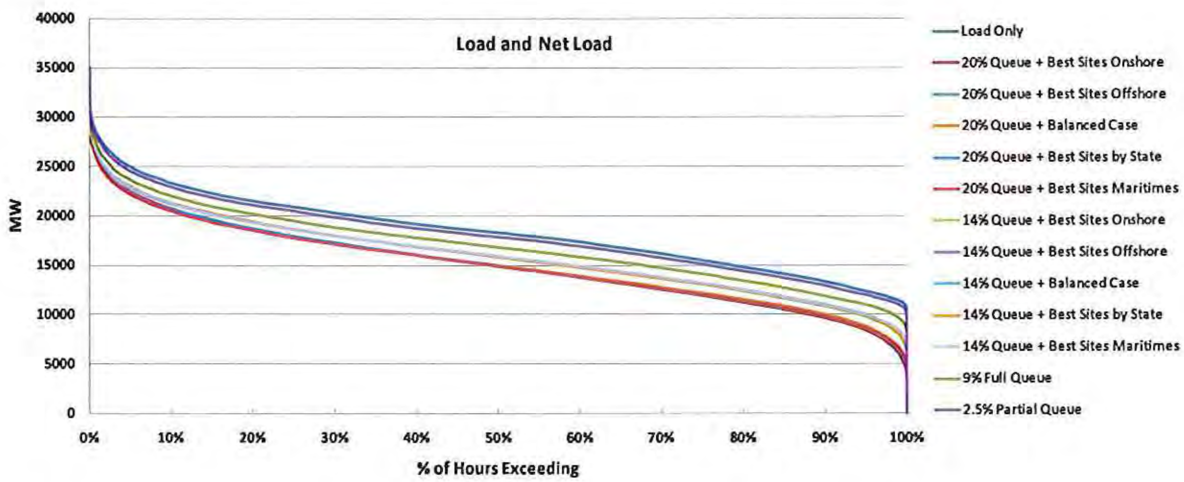


Figure 3–26 Duration curves for load and load net wind, all scenarios, all years, all hours

The substantial smoothing resulting from averaging over a large number of hours disguises many of the important operational challenges that may be imposed by wind generation. Other views of the data can reveal more regarding impacts of wind variability on the net load. Figure 3–27 shows the hourly changes in ISO-NE load for all three years of data. Hourly changes in wind generation are shown for all scenarios in Figure 3–28 through Figure 3–30. It is apparent from the respective distributions that the lower penetration scenarios would not have much effect on the aggregate changes when combined with load, with increasing influence as the penetration grows. Again, the specific impacts must be evaluated through chronological production simulations, as the ability of the ISO-NE fleet to respond to changes in demand will depend on factors beyond wind and load.

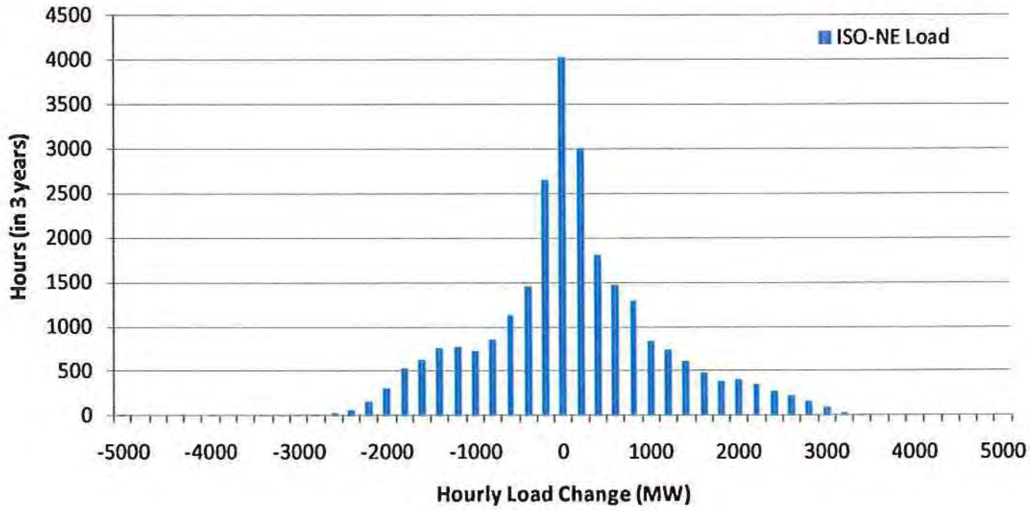


Figure 3–27 Distribution of all hourly ISO-NE load changes (3 years of data)

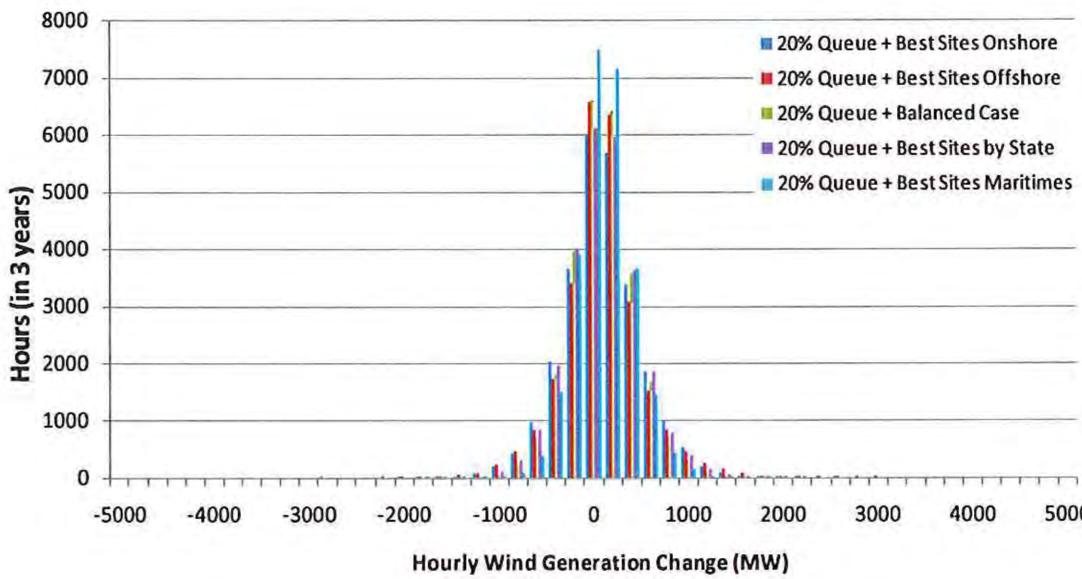


Figure 3–28 Hourly changes in wind generation for 20% penetration scenarios

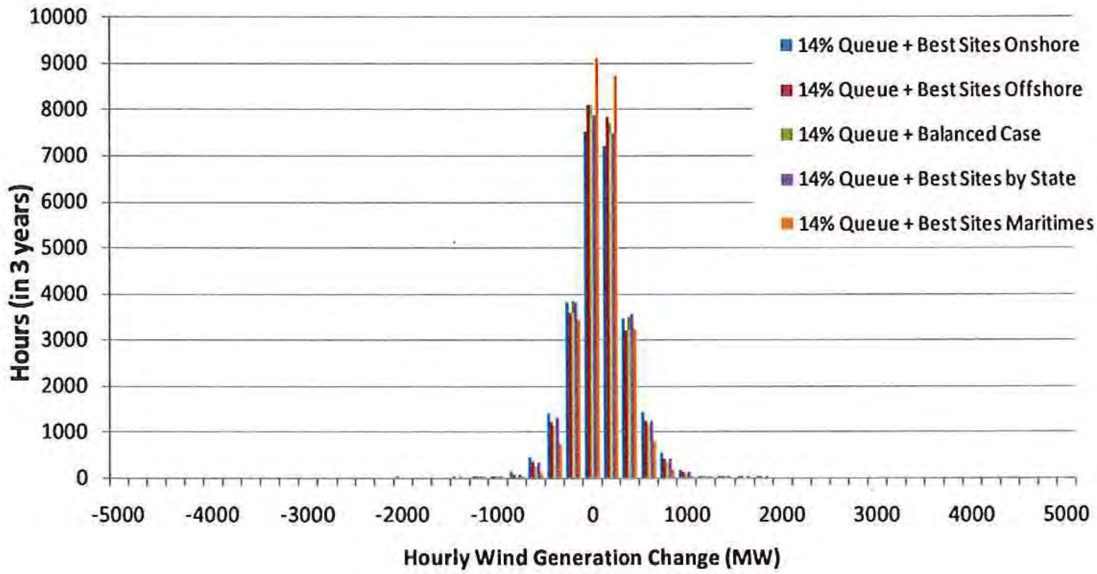


Figure 3–29 Hourly changes in wind generation for 14% wind penetration scenarios

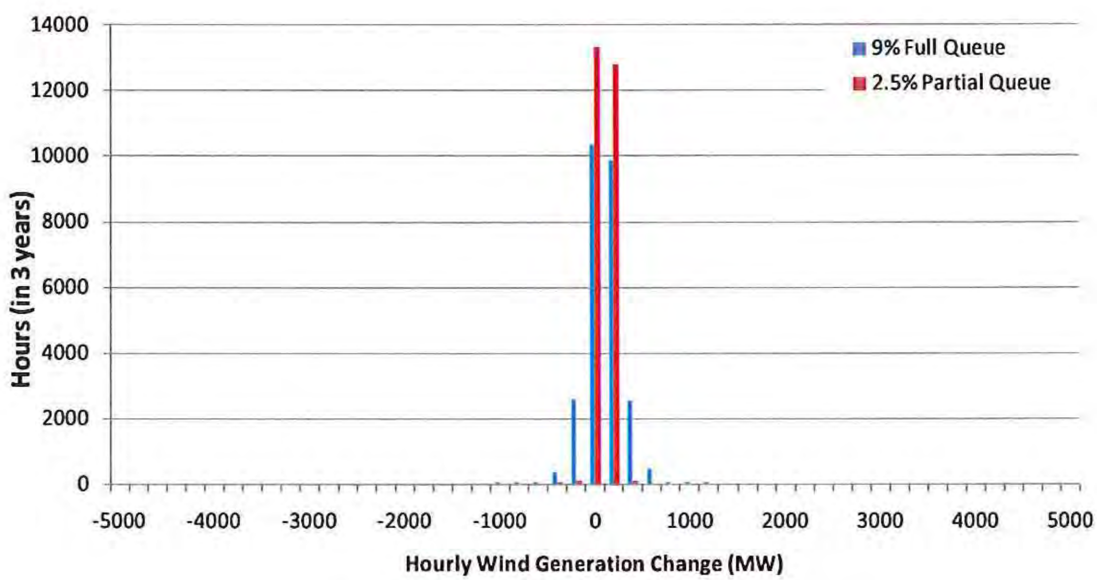


Figure 3–30 Hourly changes in wind generation for lower penetration wind scenarios

Some general operational impacts are better viewed as a comparison of the distribution of hourly changes in ISO-NE load only to those of the net load in the scenarios. These comparisons are depicted in Figure 3–31 through Figure 3–34 for 2.5%, 9%, 14%, and 20% penetration scenario, respectively.

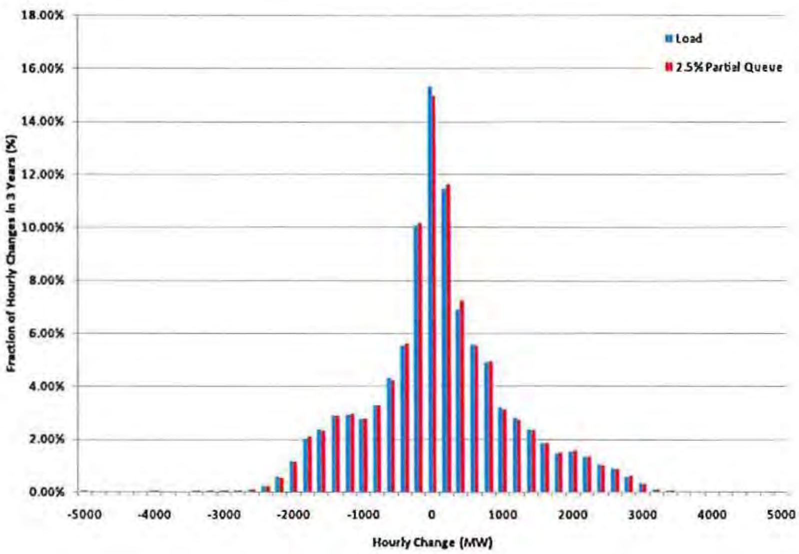


Figure 3–31 Hourly change in ISO-NE load and net load for 2% Partial Queue (3 years of data)

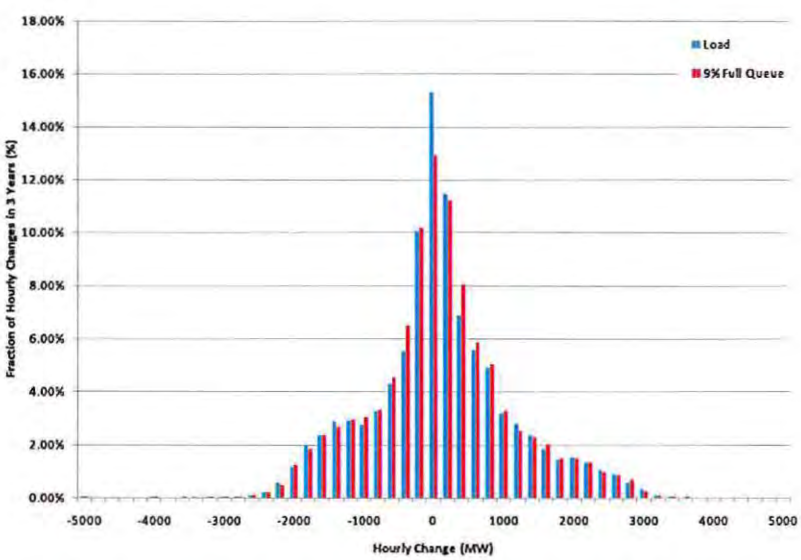


Figure 3–32 Hourly change in ISO-NE load and net load for 9% Full Queue (3 years of data)

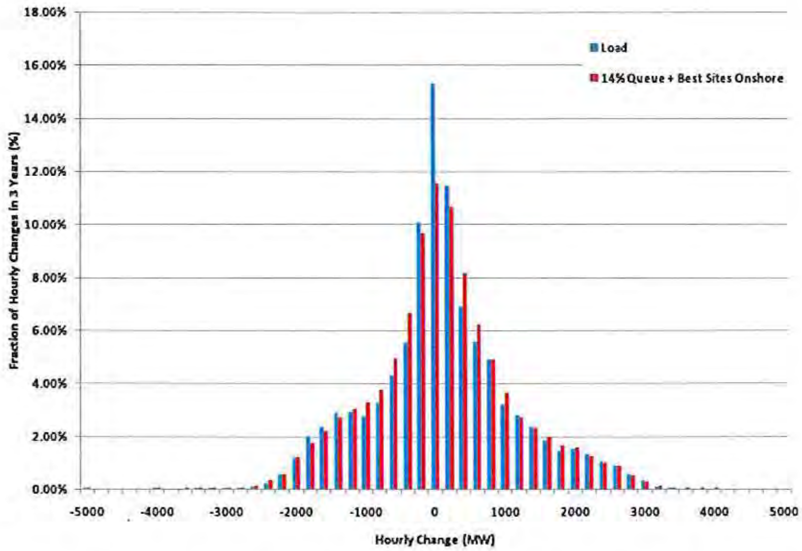


Figure 3–33 **Hourly change in ISO-NE load and net load for 14% Queue + Best Sites Onshore scenario (3 years of data)**

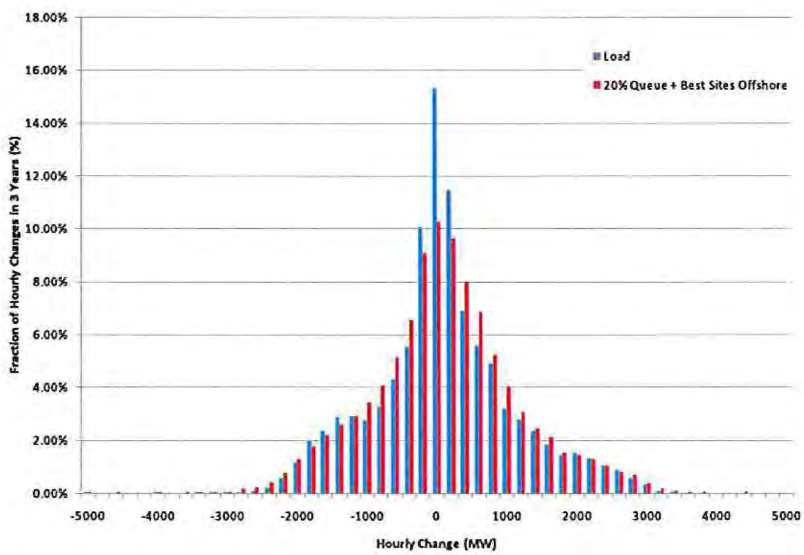


Figure 3–34 **Hourly change in ISO-NE load and net load for 20% Queue + Best Sites Onshore scenario (3 years of data)**

Even for the 20% scenario, the difference between the load only and net load case is relatively subtle. Expanding the view on the tails of the distribution for the 20% Queue + Best Sites Onshore case (Figure 3–35) helps to reveal the impact of wind generation.

It can be seen from the figure that the number of extreme hourly changes is increased with wind generation. Each 0.10% increment on the vertical axis corresponds to about 26 events over the 3 year data record. The right half of the picture shows that there are several (about 10 for this particular scenario) hourly increases in net load for this scenario that are greater than those observed for load alone.

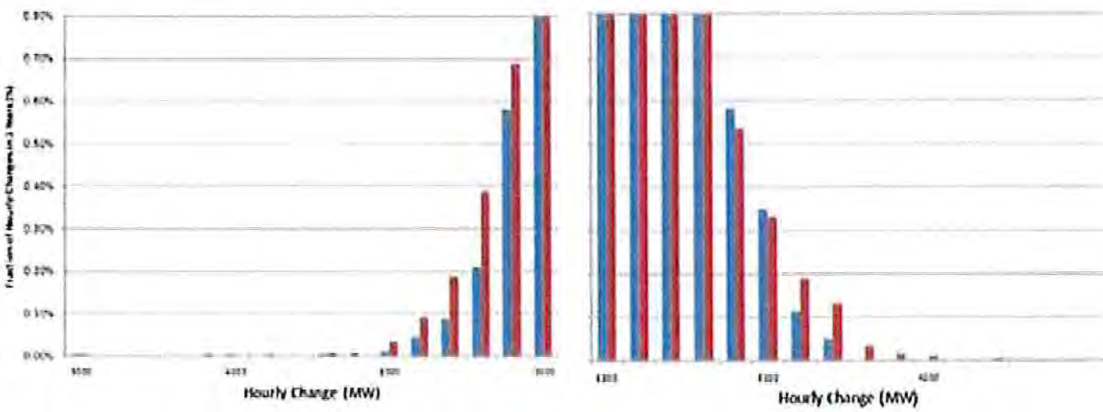


Figure 3–35 Tails of the distribution of hourly changes for ISO-NE load and net load for 20% Queue + Best Sites Onshore scenario

Any increase in the number or magnitude of extreme hourly changes is important operationally. Views through comparison of hourly load and net load data can confirm their size and existence, but say little about specific impacts on the ISO-NE system. The hourly production simulations described in a later section are where the real operational impacts are assessed and quantified. The extreme events that can be identified in the statistical and quantitative characterizations are evaluated in the appropriate context of the entire power system, its individual elements, and the full range of operating constraints.

3.1.5 Faster Variations in Wind Generation

The discussion thus far has focused on variations in wind generation, ISO-NE load, and load net of wind generation on an hourly basis. Chronological production simulation at one-hour time steps is the primary analytical machinery for this wind integration study; via these simulations, each actual day which contributes a small amount to the hourly averages above will be examined in detail. Consequently, the preceding discussion is intended to provide an overview of the major impacts of wind generation on the net demand against which ISO-NE generating resources will be committed and dispatched. The chronological production simulations will provide the quantitative detail regarding wind generation impacts on ISO-NE operations.

Variations of load and wind generation on smaller time scales are also important operationally. Because these cannot be directly evaluated through hourly production simulations, characterizations of the faster variations in load and wind will be used later to ascertain additional operation impacts such as incremental regulation needs and operating reserve impacts.

The data used for this analysis consists of ten-minute resolution wind data from the wind data set. A first measure of the variability within the hour can be made by simply looking at the magnitude change from one interval to the next.

Figure 3–36, Figure 3–37, and Figure 3–38 contain pictures of the wind generation variability from one ten minute interval to the next for each scenario. Changes in production to the next interval are plotted on the vertical axis against the current production level on the horizontal. The spread from top to bottom across each "cloud" s a measure of the within-hour volatility, and illustrates directly how wind generation can increase the range of maneuverable generation necessary to balance supply and load.

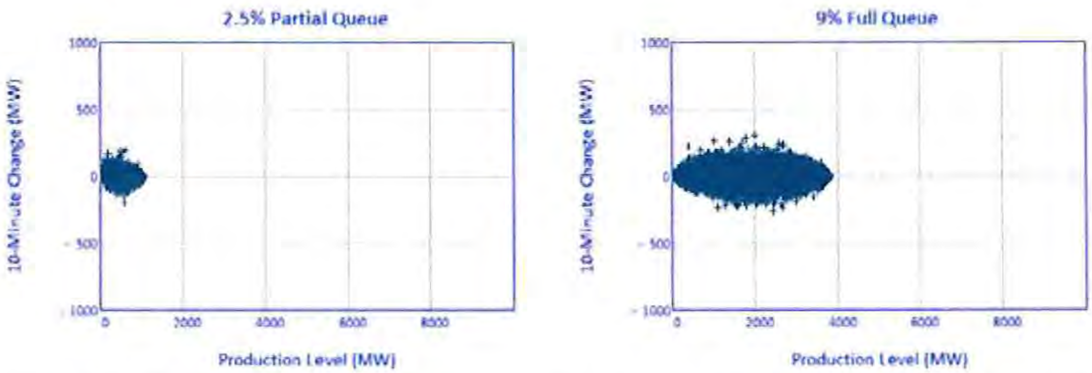


Figure 3–36 "Cloud" charts showing ten-minute variability as a function or wind production level 2.5% and 9% scenarios

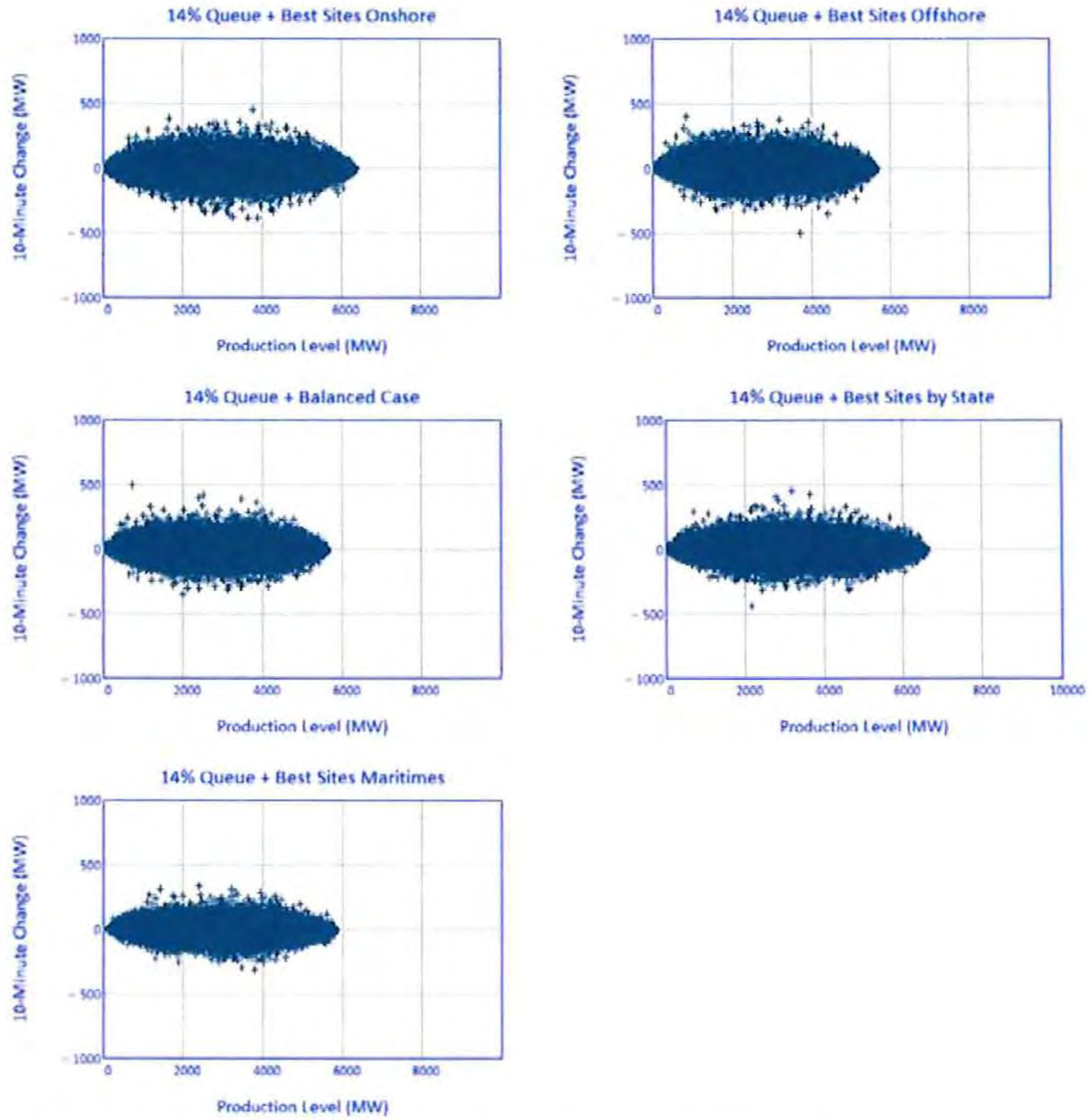


Figure 3–37 Ten-minute variability as function of production level for 14% scenarios

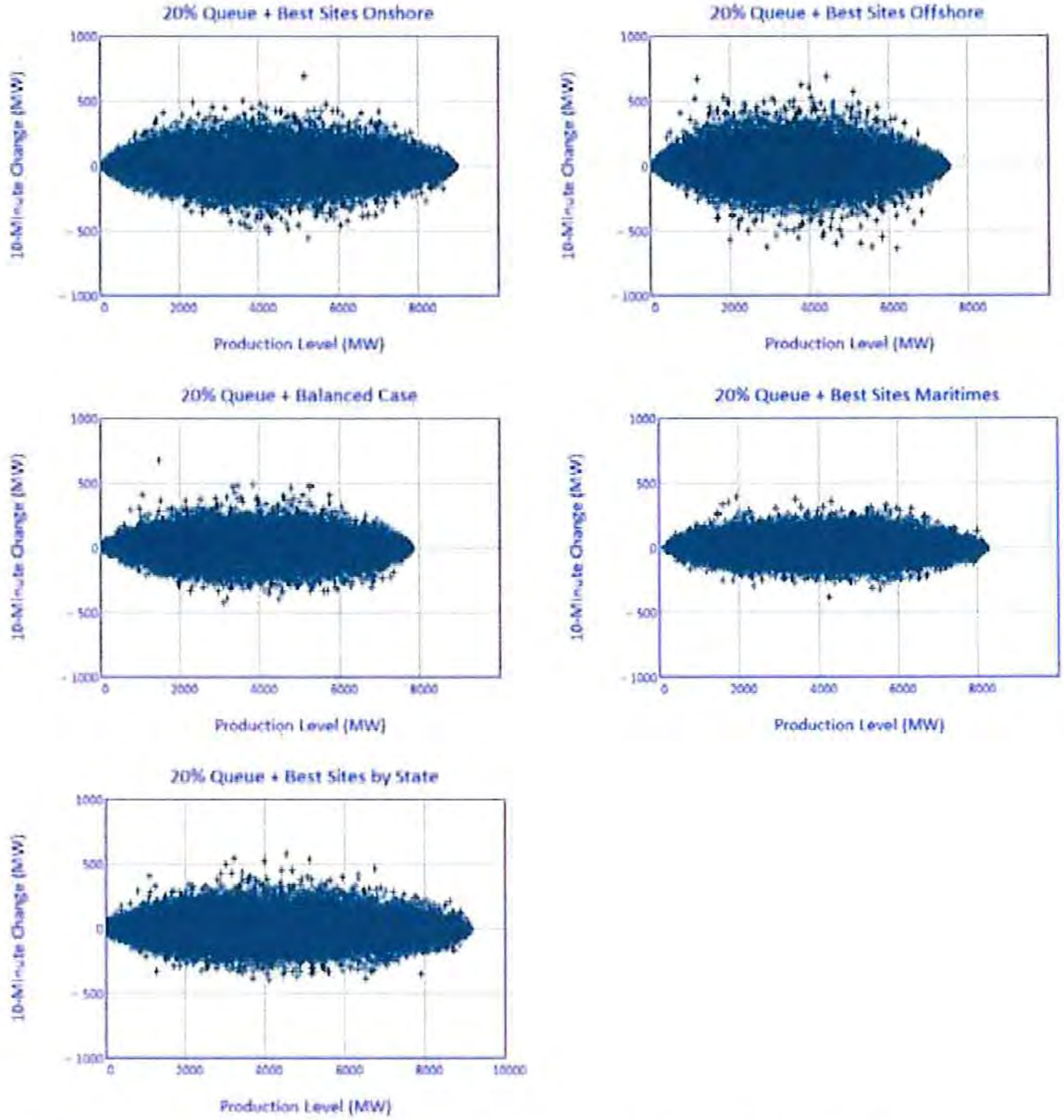


Figure 3–38 Ten-minute variability as function of production level for 20% scenarios

Statistics of the ten-minute variability of aggregate wind generation provides a useful characterization that will be used later in quantitative analysis of regulation needs and operating reserve impacts. Figure 3–39 is a modification of the cloud charts above. Ten-minute variations (changes from one data point to the next in the ten-minute dataset) are grouped by the average hourly production level during the time the variation occurred. Hourly production levels are then organized into "bins," where the 10% to 20% bin, for example, contains all of the ten-minute variations that occurred when the hourly production was between 10 and 20% of aggregate nameplate capacity.

Once sorted, the standard deviation of the variations in each bin is computed, and plotted against production level, as shown by the red squares in Figure 3–39. Three years of ten-minute data result in over 150,000 samples. Because of the large sample size, the distributions in each bin are quite Gaussian, so the standard deviation becomes a useful metric for calculating the expected magnitude of variations.

The shape of the curve in Figure 3–39 bears some explanation. At low levels of wind generation, the expected variations are small mainly due to low wind speed levels. The expected variations are highest near 50% of nameplate production because wind speeds are such that each turbine is operating on the steepest portion of the power curve (power is a function of the wind speed cubed). As the aggregate production level increases further, winds are more vigorous and there is a larger probability that at least some of the individual turbines in the aggregate are operating above rated wind speed. In this region, variations in wind speed have little to no impact on production, i.e. the power output of the turbine remains constant as wind speed varies. Consequently, the expected variation from one interval to the next is much smaller than at lower production levels.

It must be kept in mind that these statistical characterizations of variability are applied to all of the wind turbines in the scenario as a whole. They are useful here because of the large amounts of wind generation assumed for each scenario. In practice, a similar approach might be used. Wind plant production data from EMS archives – which would be of much higher resolution (e.g. SCADA scan periodicity, about 4 seconds) that what is available for this study – can be periodically extracted and analyzed in a manner similar to what is shown here. The result would be statistical characterizations of the actual wind generation fleet that could be fed into analyses of regulation and operating reserve needs going forward.

Figure 3–39 through Figure 3–42 show characterizations of ten-minute variations for four wind generation scenarios, using three years of data. The blue lines on each chart are approximations of the empirical data represented by the red squares. The shape suggested by the empirical data provides for a simple curve fit using a quadratic expression.

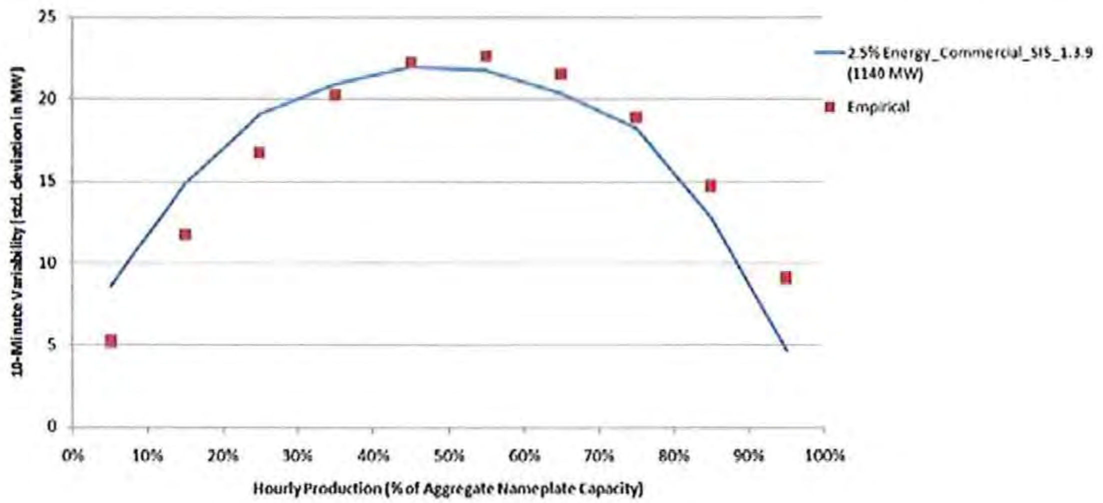


Figure 3–39 Statistical characterization of ten-minute variability for 2.5% scenario

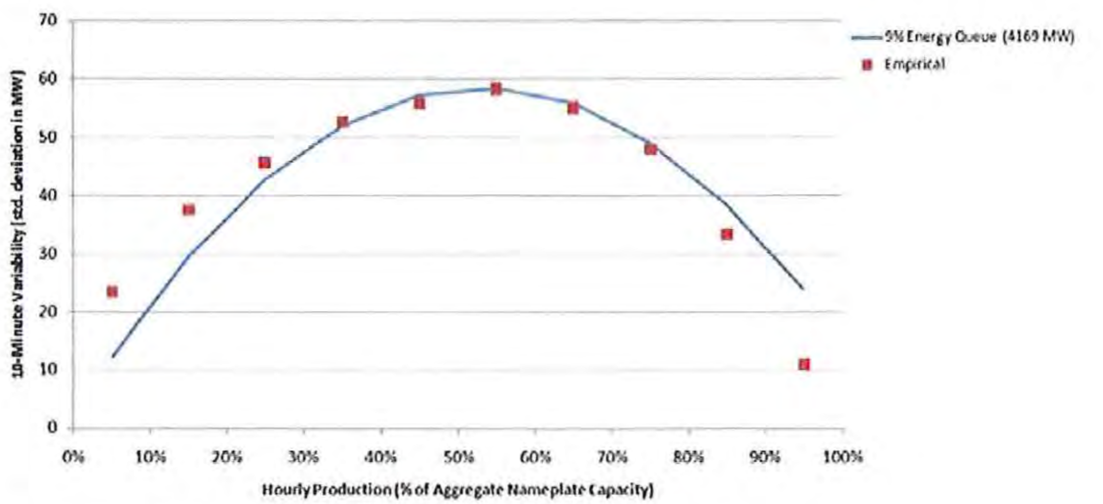


Figure 3–40 Statistical characterization of ten-minute variability for 9% scenario

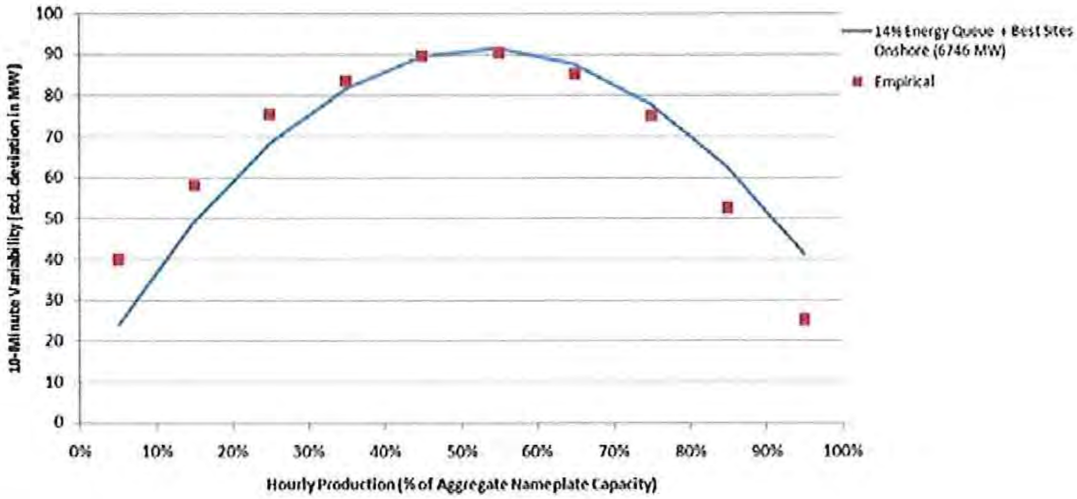


Figure 3–41 Statistical characterization of ten-minute variability for 14% scenario

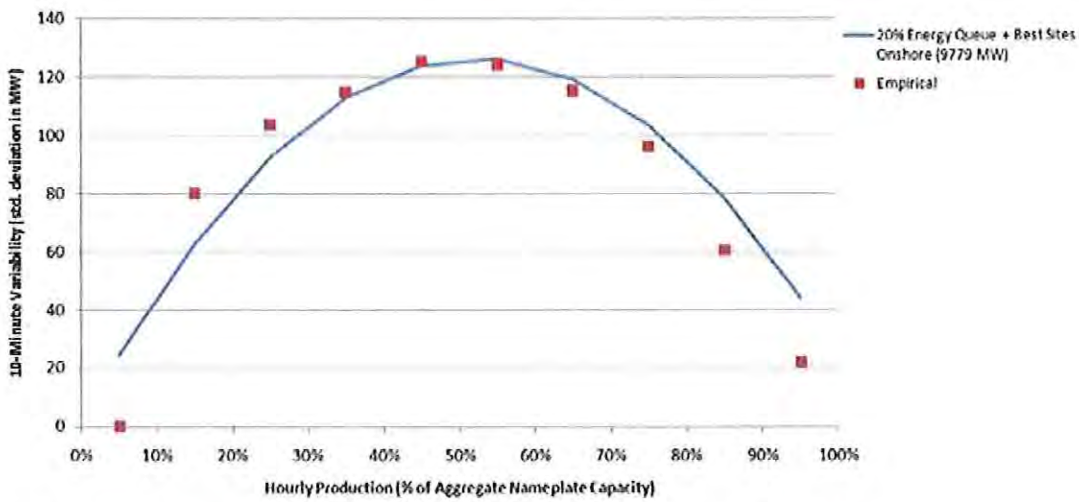


Figure 3–42 Statistical characterization of ten-minute variability for 20% scenario

Characterizations of ten-minute variability for all twelve wind generation scenarios are shown in Figure 3–43 through Figure 3–45. All curves are plotted on the same vertical scale to emphasize relative variability. As the installed capacity is increased, so does the expected variability. There are some subtle differences, however. Processing the ten-minute variability in this way actually captures some unique aspects of each scenario. For example, in Figure 3–45, substantial differences in the maximum expected variability between scenarios can be seen. While not proven rigorously, the likely explanation is that geographic diversity of the scenarios varies significantly. The "Best Sites by State" and "Best Sites + Maritimes" spread the total wind generation over the largest area. The "Best Sites Onshore" and "Best Sites Offshore" use the highest quality wind resources, thereby confining wind generation to a much smaller geographic area.

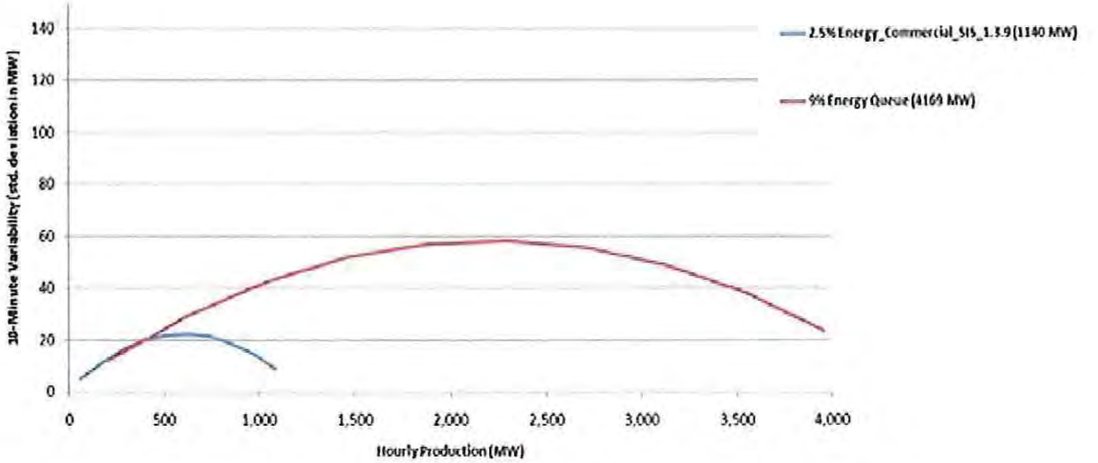


Figure 3–43 Characterization of ten-minute variability for lower penetration wind scenarios

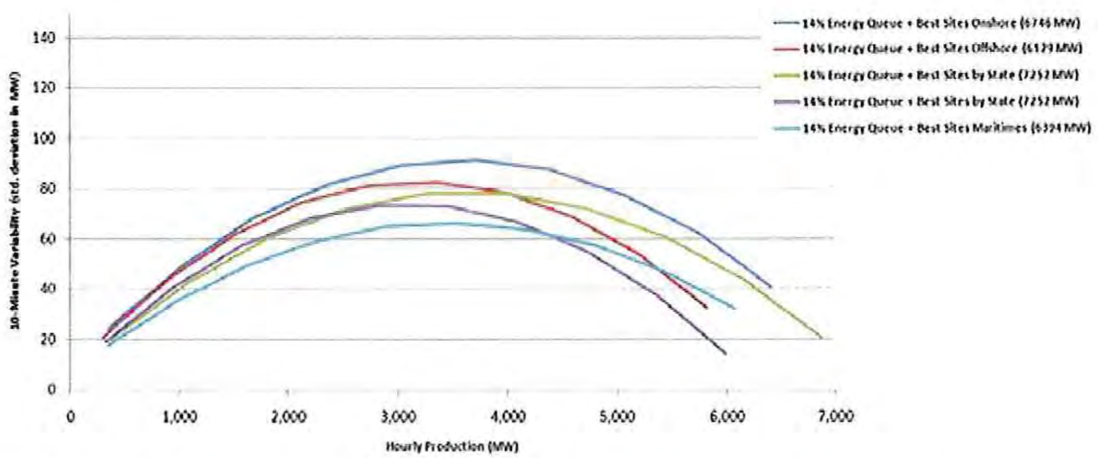


Figure 3–44 Characterization of ten-minute variability for 14% penetration wind scenarios

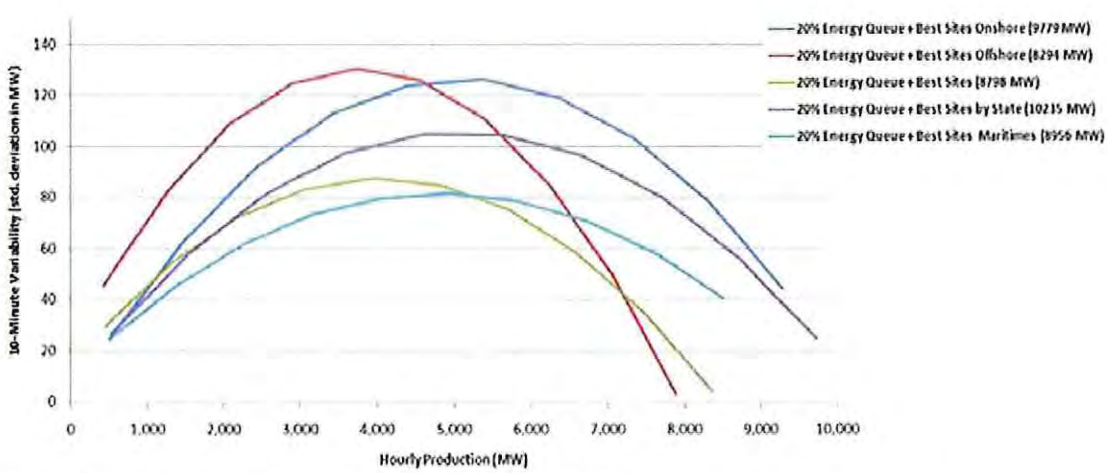


Figure 3–45 Characterization of ten-minute variability for 20% penetration wind scenarios

3.2 Wind Generation Forecasting and Uncertainty

The accuracy with which wind generation can be predicted varies with the forecast horizon. Beyond a week or so, it is nearly impossible to predict hourly production with any reasonable accuracy; forecasts based on empirical or historical data, as presented here previously, would likely be as accurate as much more sophisticated methods. Fortunately, forecast accuracy for both load and wind generation will increase as the horizon is shortened.

In power system operations, the critical horizons are those used by operators to commit, schedule, and dispatch generation. The day-ahead forecast, meaning a forecast of hourly production over the 24 hours of the next day and generated about twelve hours prior to the start of the target day, is a critical input to processes that optimize the economic efficiency of the system within security and reliability constraints. Errors in the forecast quantities – load and wind generation - that drive the commitment and dispatch processes can have consequences for the economic efficiency and/or reliability of the system. Over-forecasting of wind generation can result in commitment of too much conventional generation leading to excess uplift charges; under-forecasting may lead to depletion of reserves and very high locational marginal prices (LMPs).

Even shorter horizons are also important, as "looking ahead" is a fundamental part of power system operation. These horizons range from an hour to four or more hours into the future.

The NEWRAM dataset developed for this study also includes forecasts of production for each hour that represents a prediction made during the previous day, four hours prior to the start of the hour, and one hour prior.

The objective here is to characterize wind generation forecast accuracy for the horizons integral to the study:

- The day-ahead forecast used in unit commitment,
- An hour-ahead forecast that factors into operating reserve considerations, and
- A very short-term forecast (10-minutes ahead) that is used to assess incremental regulation needs, as will be described in Chapter 4.

3.2.2 ***Day-Ahead***

Mean-Absolute-Error is the chosen metric for forecast accuracy. It is calculated by dividing the difference between the actual and forecast value each hour by the aggregate nameplate capacity, taking the absolute value, summing over all the hours, then dividing by the number of hours.

The day-ahead forecast accuracy over all three years of the NEWRAM dataset for each scenario is shown in Figure 3–46. The values are consistent with the current state-of-the-commercial art forecasts having MAEs in the 15 and 20% range.

Forecast accuracy varies seasonally as shown in Figure 3–47. Errors are lowest in summer, when wind production is lowest; the improved accuracy might be attributable to the differing weather patterns that drive wind generation in this season in that they are somewhat easier to forecast [see Task 2 report].

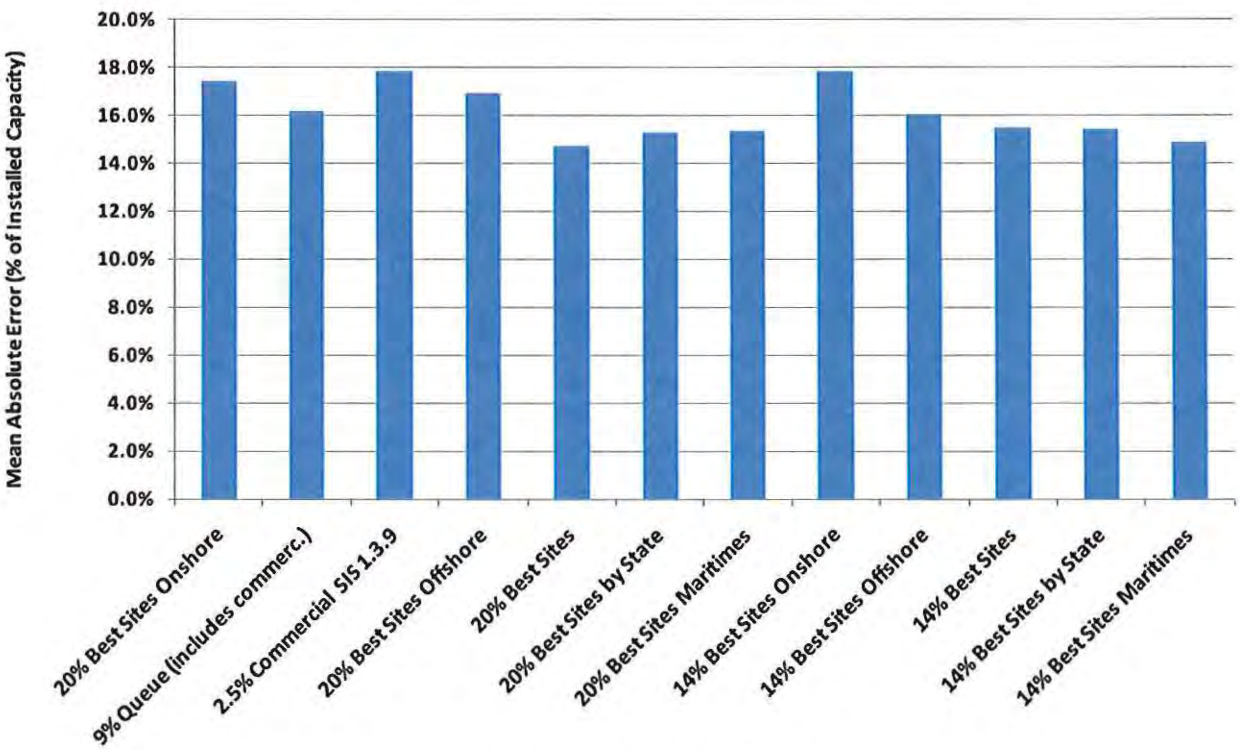


Figure 3–46 Mean-Absolute-Error for day-ahead forecast, all scenarios, all hours

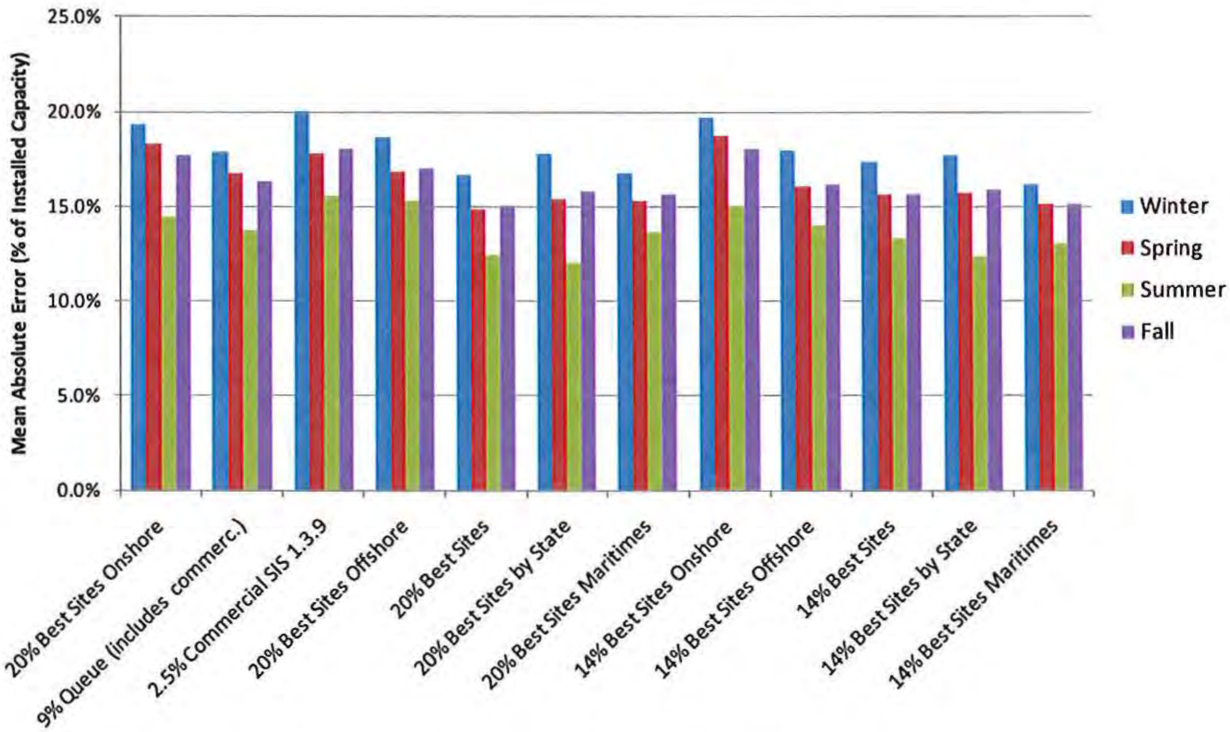


Figure 3–47 Day-ahead forecast accuracy for each wind generation scenario

MAE is sometimes a misleading statistic as it normalizes all error to the nameplate capacity. Large differences between actual and forecast wind generation at lower levels of production are reduced in "appearance" when divided by nameplate capacity. In absolute terms, there will be many hours with significant differences between forecast and actual wind. Figure 3–48 illustrates hourly forecast and actual wind generation for randomly selected seven-day periods for the 20% Queue + Best Sites Onshore scenario.

The graphs show that the day-ahead forecasts provided with the mesoscale wind production data, and representing the state of the commercial art for wind generation forecasting, track the trends in the actual wind generation quite well. Closer inspection, though, shows some hours with very large errors. On the chart for the week in June, for example, actual wind generation is under-forecast by over 3000 MW for a few hours just prior to June 20th. In the October chart, over-forecasts of a similar magnitude are seen in the first hours of the record.

The production simulations can help reveal the significance of these errors with respect to system reliability and economics. Going forward, there are some significant outstanding questions regarding use of wind generation forecasts in the various operational contexts. In wholesale energy markets, for example, wind generation scheduled only in real-time or in short-term markets has the effect of ensuring over-commitment in the day-ahead market. On the other hand, over-forecasting of wind generation in the day-ahead reliability commitment may pose risks to system security.

These questions are now beginning to be addressed as the amount of wind generation becomes visible in energy markets and other operating regimes.

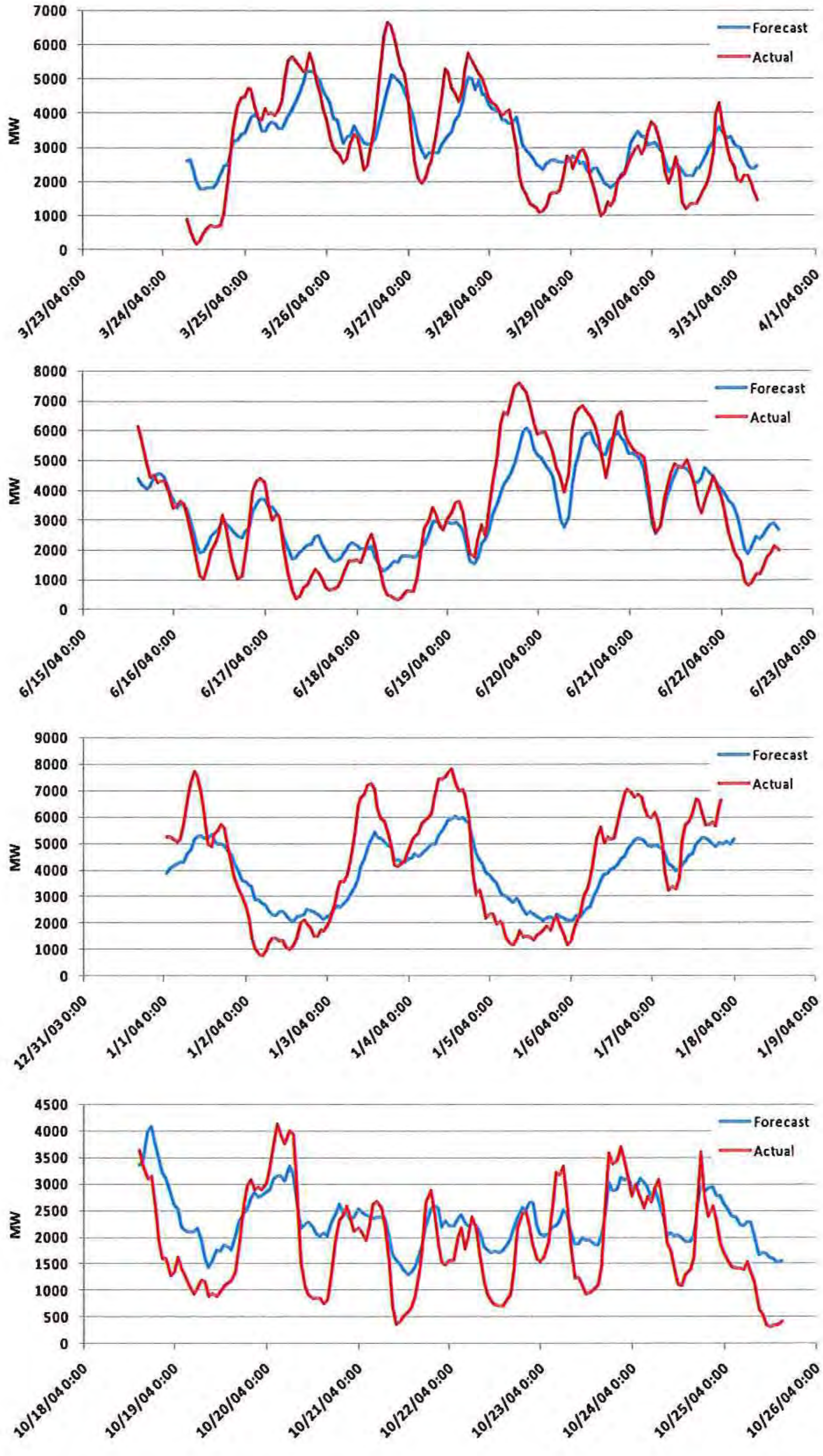


Figure 3–48 **Day-ahead forecast and actual wind generation for selected weeks from each season; "20% Queue + Best Sites Onshore" scenario**

3.2.3 Hour-Ahead

At one-hour horizons, "persistence" forecasts have been shown to be as statistically accurate as those based on more sophisticated techniques or atmospheric modeling. Persistence forecasts simply assume that things will not change – the forecast for the next interval is what is measured in the current interval.

Persistence forecasts are also simple to generate, and therefore are used in this study as a proxy for short-term wind generation forecasts. While the overall accuracy, as mentioned above, is good relative to other methods, they are of limited use in volatile wind conditions that may lead to large ramps in wind generation. Research is ongoing on special techniques for forecasting these conditions and better predicting large changes in wind generation. For purposes of this study, though, persistence is used due to its simplicity and the lack of hard data with respect to current or future ramp forecasting accuracy.

For 1-hour persistence, the forecast is the current hour's value, and any changes from the current hour are directly equal to the forecast error. Previous views of the hourly changes are also characterizations of the 1-hour persistence forecast error. The chart in Figure 3–49 (which is identical to the chart in Figure 3–28) shows the distribution of all hourly errors for the 20% scenarios.

A more useful representation of persistence forecast errors is shown in Figure 3–50. In this chart, the errors are grouped by hourly production level, as with the ten-minute data earlier in this section. The expected error changes with production level and the empirical data can be simply approximated with a quadratic expression.

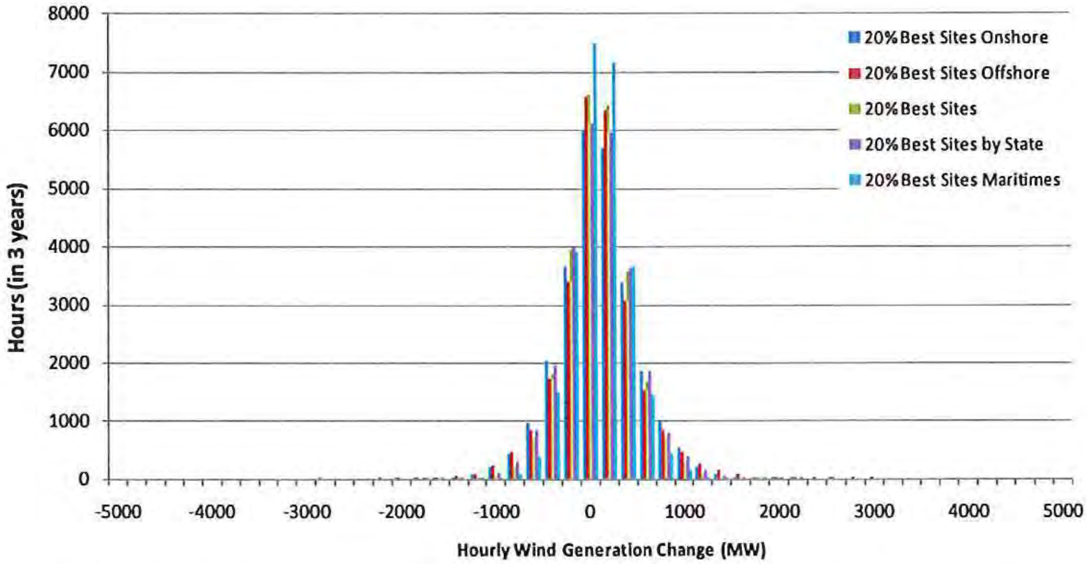


Figure 3–49 Distribution of 1-hour persistence forecast errors for 20% wind generation scenarios

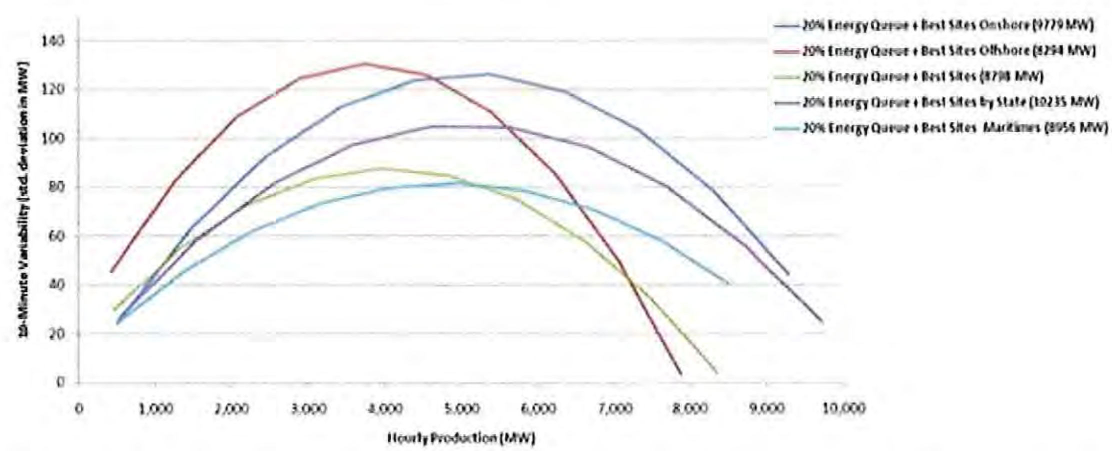


Figure 3–50 Expected 1-hour persistence forecast error as function of current production level for 20% scenarios

3.2.4 Very Short Term

Persistence forecasts over very-short term intervals are statistically more accurate than those over an hour. The charts characterizing wind generation changes over ten-minute intervals, appearing earlier as Figure 3–43, Figure 3–44, and Figure 3–45 in the discussion of variability, also characterizes expected forecast error over a ten-minute interval as a function of production level. These will be used later in the examination of incremental regulation and within-hour flexibility requirements.

3.3 Statistical Characterization Observations and Conclusions

The observations and conclusions here are made on the basis of three years of synthesized meteorological and wind production data corresponding to calendar years 2004, 2005, and 2006. In some senses, the sample size is very adequate, as the behavior of wind generation under many types of weather regimes is embedded in the dataset. In other respects, though, there may be some inadequacies. For example, inter-annual variability is known to be an important question for wind generation. With a limited sample size in terms of the number of years represented, there is no way to tell from the dataset alone whether annual energy production, for instance, is lower, higher, or about equal to what might be expected annually over the life of a wind project. Other resources, such as long-term meteorological records, would need to be consulted to provide insight into these types of questions.

The wind generation scenarios defined for this study show that the winter season in New England is when the highest wind energy production can be expected. As is the case in many other parts of the U.S., summertime is the "off-season" for wind generation.

The capacity factors for all scenarios follow the same general trend. Seasonal capacity factors above 45% in winter are observed for several of the scenarios. In summer, capacity factors drop to less than 30%, except for those scenarios that contain a significant share of offshore wind resources.

Based on averages over the entire dataset, seasonal daily patterns in both winter and summer exhibit some diurnal behavior. Winter wind production shows two daily maxima, one in the early morning after sunrise, and the other in late afternoon to early evening. Summer patterns contain a drop during the nighttime hours prior to sunrise, then an increase in production through the morning hours. It is enticing to think that such patterns could assist operationally with morning load pickup and peak energy demand, but the patterns described here are averages of many days. The likelihood of any specific day ascribing to the long term average pattern is small.

The net load average patterns by season reveal only subtle changes from the average load shape. No significant operational issues can be detected from these average patterns. At the extremes, the minimum hourly net load over the data set is influenced substantially. In one of the 20% by energy scenarios, the minimum net load drops from just about 10 GW for load alone to just over 3 GW. The very substantial additional turn-down on that particular day would be very noticeable operationally (and is evaluated directly in the hourly production simulations).

The day-ahead forecasts developed for each scenario from information in the NEWRAM dataset show an overall forecast accuracy of 15% to 20% Mean Absolute Error (MAE). This is consistent with what is considered the state of the commercial art. Day-ahead forecasts for all scenarios are important since they will be used directly in the hourly production simulations, and represent the major source of uncertainty attributable to wind generation.

Shorter-term forecasts also factor into operations. For reserves, the most important of these are the short-term hour ahead and ten-minute ahead forecasts. The process for generating these normally uses persistence, which assumes that there will be no change in wind generation over the forecast horizon. Persistence has been shown to be as statistically accurate as forecasts based on skill and sophistication (though skill-based forecasts may be much better during periods of predictable changes). The various statistical characterizations developed to portray the variability and short-term uncertainty of the aggregate wind generation in each scenario are also critical inputs to the analysis of operating reserve impacts in the next chapter.

4 Impact on ISO-NE Operating Reserves

4.1 General

The objective of this portion of the analysis is to evaluate how various levels of wind generation might impact ISO-NE policies and practices for operating reserves. Currently, ISO-NE defines three categories of operating reserve:

- 10-minute spinning reserve – TMSR
- 10-minute non-spinning reserve – TMNSR
- 30-minute operating reserve – TMOR

The ten-minute reserve requirement is based on the largest credible single contingency[68], which varies with system conditions; usually 50% (but sometimes as low as 25%) of the contingency amount is carried as spinning reserve (TMSR), and 50% as 10-minute non-spinning reserve (TMNSR). The 30-minute operating reserve (TMOR) requirement is 50% of the second largest credible contingency.

The dynamic nature of the ISO-NE reserve requirements was difficult to model directly in the production simulations, so an approximation was derived with the guidance of ISO-NE staff. For the calculations here, and in the production simulations described later, procurement of reserves was assumed to be a function of day type and time of day, as follows:

- 0700-2300 Weekdays
  - Total 10 minute reserve = 1500 MW, 750 of which will be 10-minute spin (750 MW TMSR, 750 MW TMNSR)
  - 30-minute reserve (TMOR): 750 MW
  - The total 10-minute and 30-minute reserve would be 2250 MW
- 2300-0700 Weekdays and all hours Weekends.
  - Total 10 minute reserve: 1300 MW; 650 of which will be 10-minute spin (650 MW TMSR, 650 MW TMNSR)

[68] "Credible" is based on a set of stress tests defined by NPCC and augmented by ISO-NE for the purposes of determining operating reserve contingencies to be planned for. More severe "extreme" contingencies may require additional operator and/or automatic intervention including shedding of firm load.

- 30-minute reserve (TMOR): 650 MW
- The total 10-minute and 30-minute would be 1950 MW

ISO-NE procures regulation capacity separately in the ancillary services market, but the amount of regulation carried is counted toward TMSR. The amount needed is based on careful analysis of load behavior, and varies by season, day type, and hour. The regulation schedule for weekdays in 2008 is provided in Table 4–1 as an illustration.

Table 4–1 ISO-NE 2008 Regulation Schedule for Weekdays

day	hour	jan	feb	mar	apr	may	jun	jul	aug	sep	oct	nov	dec
week	1	90	90	90	50	50	90	90	90	50	50	90	90
week	2	30	30	30	50	50	30	30	30	30	30	30	30
week	3	30	30	30	50	50	30	30	30	30	30	30	30
week	4	30	30	30	50	50	30	30	30	30	30	30	30
week	5	30	30	30	50	50	30	30	30	30	30	30	30
week	6	140	140	140	100	100	150	150	150	100	100	140	140
week	7	170	170	170	200	200	180	180	180	180	180	170	170
week	8	170	170	170	170	170	180	180	180	150	150	170	170
week	9	100	100	100	100	100	110	110	110	80	80	100	100
week	10	50	50	50	90	90	50	50	50	50	50	50	50
week	11	50	50	50	90	90	50	50	50	50	50	50	50
week	12	50	50	50	90	90	50	50	50	50	50	50	50
week	13	50	50	50	90	90	50	50	50	50	50	50	50
week	14	50	50	50	90	90	50	50	50	50	50	50	50
week	15	50	50	50	90	90	50	50	50	50	50	50	50
week	16	50	50	50	90	90	50	50	50	50	50	50	50
week	17	80	80	80	90	90	80	80	80	70	70	80	80
week	18	80	80	80	110	110	80	80	80	80	80	80	80
week	19	80	80	80	110	110	80	80	80	80	80	80	80
week	20	80	80	80	110	110	80	80	80	80	80	80	80
week	21	80	80	80	110	110	80	80	80	80	80	80	80
week	22	110	110	110	150	150	120	120	120	110	110	110	110
week	23	160	160	160	170	170	160	160	160	160	160	160	160
week	24	160	160	160	170	170	160	160	160	160	160	160	160

Hourly regulation varies from a low of 30 MW (overnight on weekends) to a high of 200 MW (spring morning load pickup). Over all hours of 2008, the weighted average hourly regulation is about 80 MW.

Wind generation will increase the real-time variability and short-term uncertainty of the net load against which other resources are scheduled and dispatched.

4.2 Methodology

Chronological production simulations at hourly resolution have become the standard approach for assessing wind integration impacts. Effects of wind inside of the hour on regulation, balancing, and reserves in general cannot be directly evaluated at that granularity. Consequently, statistical techniques have been developed for application to hourly and higher resolution wind and load data to estimate the impacts within the hour.

4.3 High-resolution analysis

Statistical analysis of wind and load data is employed to determine how much additional regulation capacity would be required to maintain CPS1 and CPS2 metrics in each of the wind scenarios. The data available for this analysis consists of high-resolution (10-minute interval) load and wind generation data, compiled for the study from actual load data for 2004, 2005, and 2006, and synthetic wind generation data from the ISO-NE mesoscale data. Additionally, one-minute resolution data for ISO-NE load provided for an earlier study was used.

Additionally, wind production data at 1-minute resolution was synthesized for a portion of the analysis. The procedure used is based on previous high resolution measurements of large wind plants and groups thereof that reveal a normally-distributed random behavior of faster variations about a trend.[69]

ISO-NE operating structure forms the primary backdrop for the analysis. The movement of generation in real-time operations is assumed to be in response to:

- The sub-hourly market, where clearing points are determined in advance based on short-term (10 to 20 minute) forecasts of demand and participating generation is economically dispatched, or
- Automatic Generation Control (AGC) signals to units participating in the regulation market to correct for Area Control Error (ACE) between sub-hourly market intervals

The first objective of the statistical analysis is to analyze the fast fluctuations of wind generation relative to similar variations in the load. Using the one-minute resolution load data as a reference, the fast variations are computed as the difference between the data and a twenty minute rolling average window to the 1-minute data (10 samples before and 10 samples following). Results are shown in Figure 4–1.

[69] Wan, Yih-Huei and Bucaneg, Demy "Short Term Fluctuations of Large Wind Power Plants" NREL/CP-500-30747, January 2002

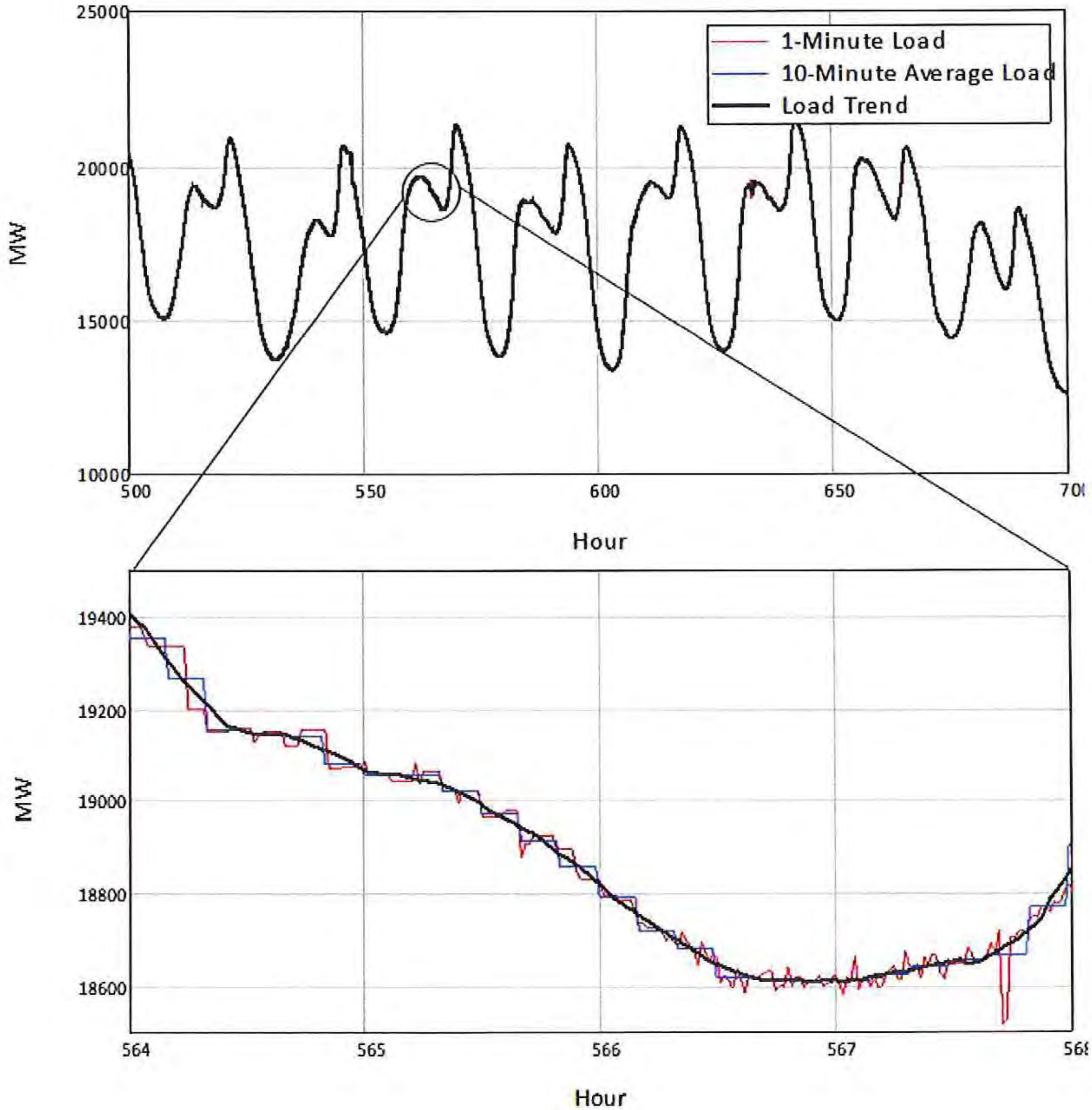


Figure 4–1 Six-day sample of 1-minute load data with trend and ten-minute averages for variability analysis

Of interest here is the deviation of the one-minute load data from the two curves, for if the constructed curves are assumed to be proxies for the variability that is compensated for by movements of generation in the sub-hourly market, the difference is what drives the need for regulation. The distributions of the differences over the 100,000 samples of one-minute data analyzed are shown in Figure 4–2. Both distributions are normal with a mean of zero, so the standard deviation is an appropriate characterization.

The requirement for regulation capacity has been approximated as a multiple of the standard deviation of the variability in this time scale. A factor of three would encompass (magnitude-wise) 99.8% of all deviations in the sample. Using this factor, the regulation capacity inferred from the statistics is 76 to 141 MW. Note that this accounts for the variability of the load only. Not included are additional deviations due to uninstructed generation movements, and ramping behavior of generation participating in the sub-hourly energy market. The regulation schedule described in Section 4.1 above accounts these factors as well as the changing variability of load with season, day type, and hour.

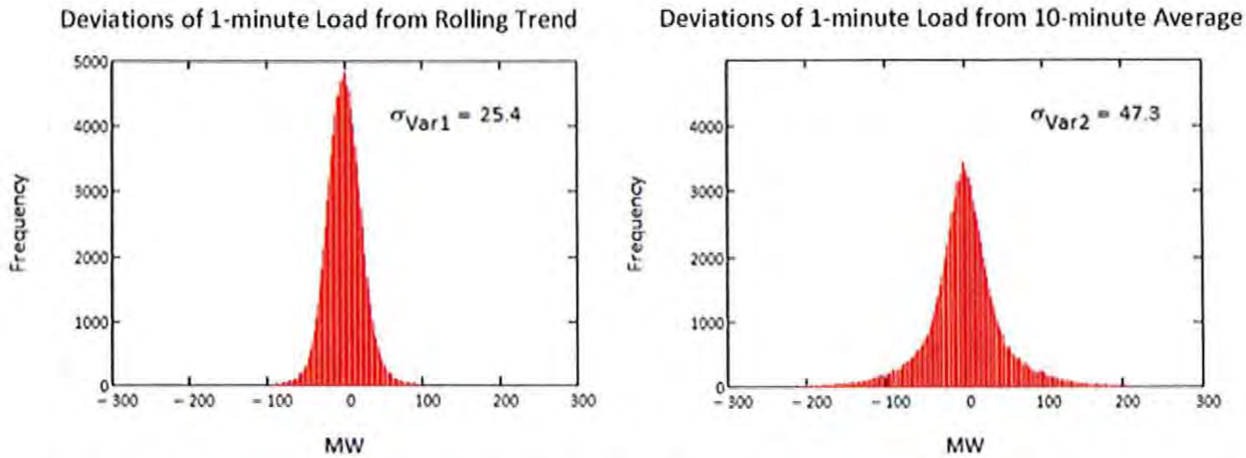


Figure 4–2 Deviations of ISO-NE 1-minute load from (l) trend and (r) ten-minute average

The ISO-NE simulated wind generation data used for this study is of 10-minute resolution, so it cannot be used directly to assess impacts of faster variations. However, extensive measurement data with time resolution down to seconds has been collected by NREL over the past decade, and other high-resolution data for wind generation has been obtained from energy management system (EMS) archives. Two observations are extracted from this measurement data for use here:

- Using the 20-minute rolling average window (used above), the standard deviation of the wind generation variations around this trend are around 1 to 2 MW for a 100 MW wind plant.
- The fast variations from a wind plant are statistically uncorrelated with similar variations from other wind plants and with those from aggregate load, and therefore can be considered in this time frame as random independent variables

The effect of the fast variations of wind generation can then be easily estimated. With 8800 MW of wind generation, approximately the amount of the 20% scenarios, the aggregate variability (i.e. deviation from the 20-minute trend) of the total wind generation can be calculated using the 2 MW assumption above:

$$\sigma_{wind} := \left(\sqrt{\frac{8800}{100} \cdot 2^2}\right) = 18.8 \quad \text{MW} \quad \text{Eq. 1}$$

And, because these variations are uncorrelated with those in load, using the standard deviation of load variations shown above in Figure 4–2, the standard deviation of the variability for net load (i.e. load net of wind generation) is calculated as:

$$\sqrt{\sigma_{Var1}^2 + \sigma_{wind}^2} = 31.6 \text{ MW} \qquad \sqrt{\sigma_{Var2}^2 + \sigma_{wind}^2} = 50.9 \text{ MW} \quad \text{Eq. 2}$$

where the first equation uses the rolling trend approximation for sub-hourly market response to load and the second uses ten-minute averages. In either case, the effect of the fast fluctuations in wind generation is quite small; the standard deviation of variability is increased from 25.4 to 31.6 MW or from 47.3 to 50.9 MW.

Over longer time scales – tens of minutes up to hours – wind generation exhibits variations that are of a markedly different character than that of load. In general, load changes over these time periods are relatively predictable, owing to both aggregation effects and a high level of familiarity based on history and heuristics. In this part of the analysis, it will be assumed that short-term forecasts of load are nearly perfect, and that sub-hourly energy markets will dispatch the necessary capacity to balance load over these intervals.

The same notion is extended to wind generation, except with recognition that short-term forecasts may exhibit appreciable error. Stated another way, sub-hourly markets will provide the necessary maneuverable capacity to balance forecast load and forecast wind generation; errors in these forecasts (for wind only, given the assumptions) will increase the regulation burden.

Figure 4–3 provides an illustration. The forecast for interval H2+20 is based on the observed wind generation during a previous interval or series of intervals, in this case the observed wind from H2+10. In the analysis here, it is assumed that the forecast for interval H2+20 is assimilated into the sub-hourly energy market clearing. The difference between the actual wind generation that appears in the interval and the forecast value will combine with the other deviations in load and generation. The aggregate of these deviations drives the requirement for regulation.

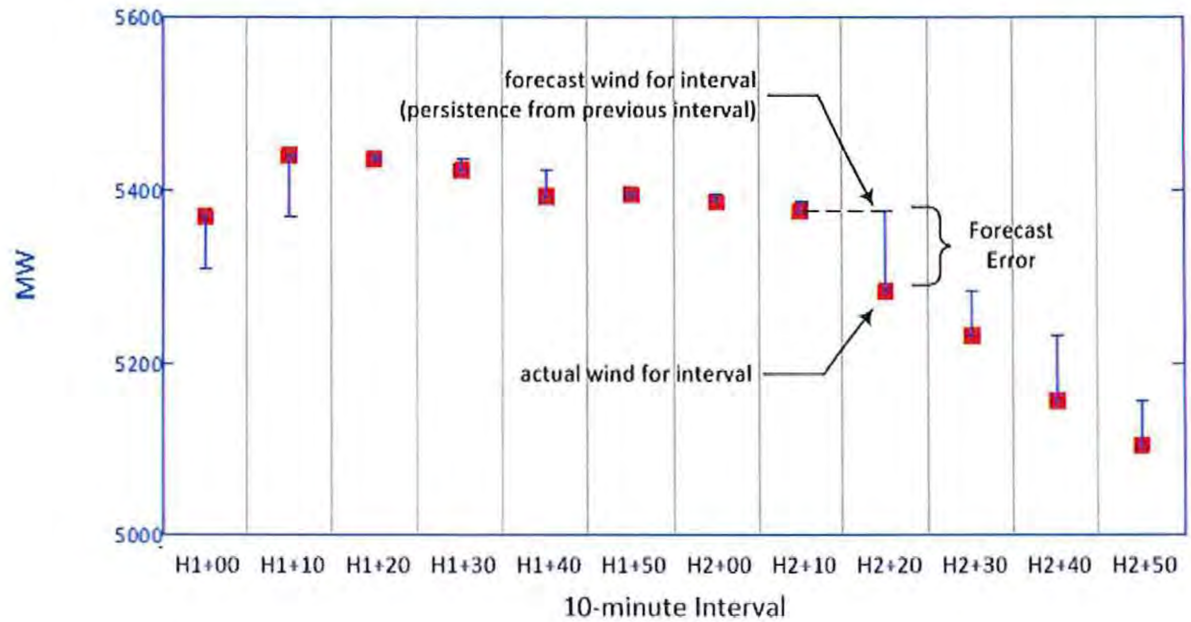


Figure 4–3 Short-term persistence forecasting for 10-minute wind generation.

Two short-term "forecast" methods were evaluated for the synthetic wind generation for three wind scenarios. The first method uses a simple persistence assumption: "Average wind generation for the next ten-minute interval will be identical to the current interval." The second method uses a sophisticated regression/curve-fitting/prediction method built into the analysis tool used here to mimic a more "intelligent" approach that presumably would outperform the persistence assumption during periods with sustained change in wind production.

After applying both methods to the data, it was found that over the sample data year (2005), the persistence method was more accurate, with a mean absolute error of 3.4% versus 4.7% for the regression/extrapolation method. Consequently, the persistence method was used for the remainder of the analysis.

Owing to the large sample of synthetic wind generation data, the expected "errors" in the persistence forecast can be mathematically characterized. Figure 4–4 shows the change in production between 10-minute intervals (i.e. the persistence forecast error) for the aggregate wind generation in the three scenarios corresponding to 8800 MW 4000 MW, and 1100 MW of wind generation (all plotted on the same scales for easier comparison). The charts are creating by plotting x-y pairs of points where x is wind generation in the current interval "i", and the y value is equal to wind generation in the next interval minus wind generation in the current interval.

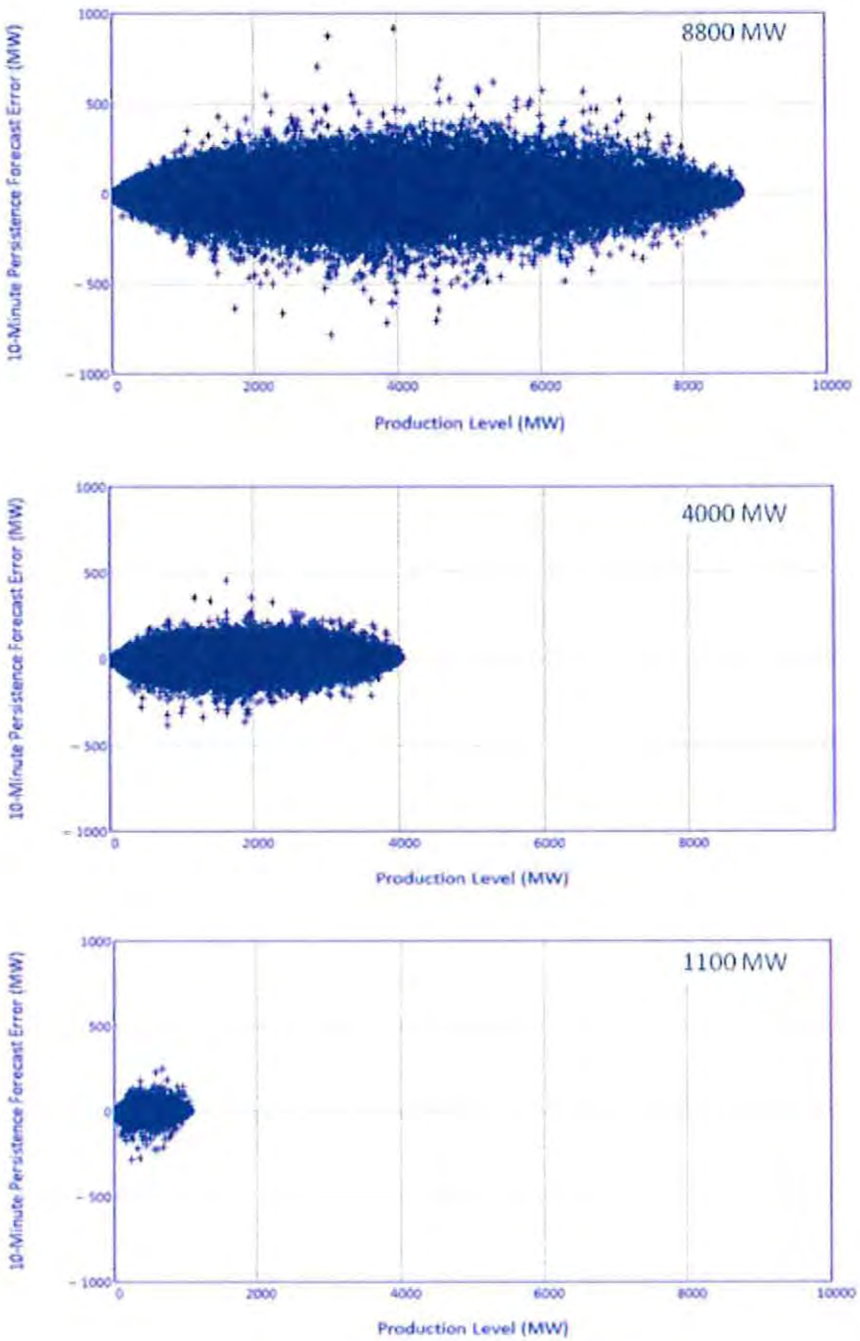


Figure 4–4 10-minute variability of three illustrative wind scenarios used for high -resolution analysis

Another view of this same variability is presented in Figure 4–5. Here, each of the changes (or forecast errors) is grouped in ten "bins" or deciles of production from 0 to 1.0 per unit of name plate rating. Then, the standard deviation of the (normal) distributions in each of the deciles is computed and plotted.

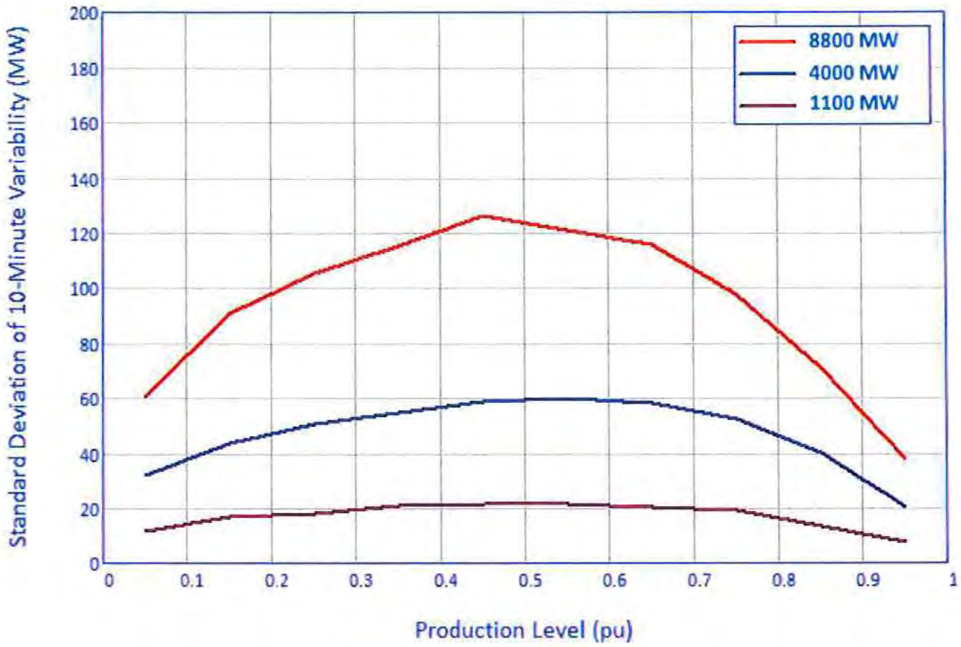


Figure 4–5 **10-minute variability of illustrative wind scenarios with hourly average production level; empirical data, in MW**

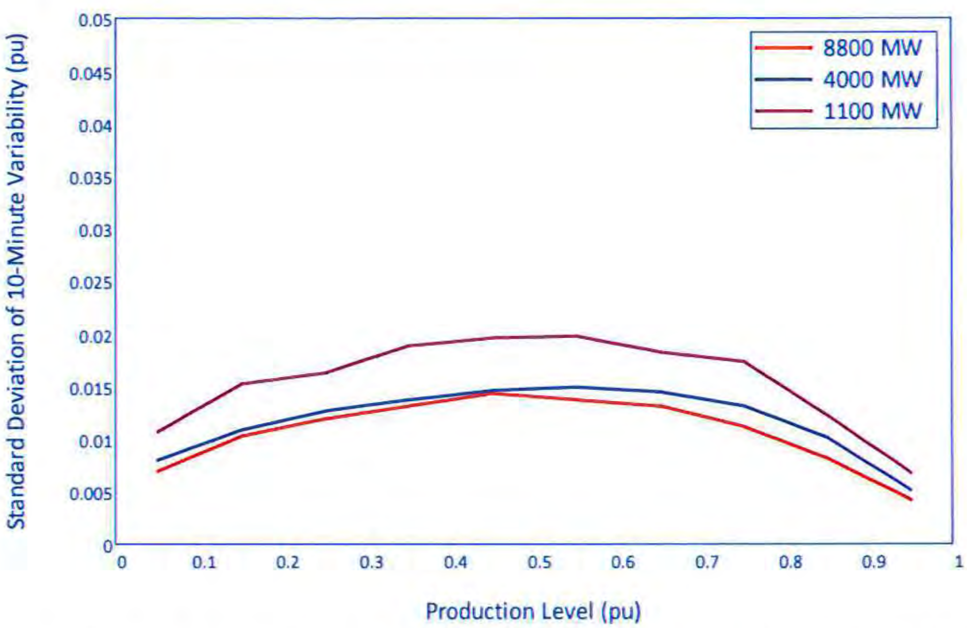


Figure 4–6 **10-minute variability of illustrative wind scenarios with hourly average production level; empirical data, per-unit of aggregate nameplate capacity for each scenario**

The scenarios analyzed above are for illustration, and are representative of the penetration levels examined in this study. In the analysis to come, the specific variability characteristics of each scenario are computed and then used in estimations of incremental regulation requirements. Characterization of the variability in this manner captures the uniqueness of each defined scenario; those with large concentrated wind generation facilities will show more variability than scenarios with much more dispersed plants. Effects of geographic diversity, as another example, can be seen in Figure 4–6, where the variability at 10 minute intervals, expressed as a percentage of total capacity, declines as the number of individual turbines in the scenario (and the total installed capacity) increases.

The curves can be approximated well with a simple quadratic expression. The utility of this approximation is that the variability can be defined by the current or forecast production level. This provides a method to procure the appropriate amount of additional regulating reserves as wind generation varies over hours or days.

4.4 Results with hourly data

The estimated operating reserve requirements for each wind generation scenario are described here. The previous discussion feeds into the regulation analysis. Beyond regulation, other calculation techniques using 10-minute wind and load data along with production simulations results from MAPS are used to assess how the ISO-NE operating reserve categories would be impacted by wind generation.

4.4.1 Regulation – Hourly Approximations

Incremental regulation requirements for each scenario are estimated as a function of the variability of ISO-NE load as implied from the scheduled regulation (see Table 4–1) and the variability of the wind generation as defined by the 10-minute "persistence forecast error" characterizations, as shown in Figure 4–7 for each of the study wind generation scenarios.

Equations which approximate the 10-minute variability as functions of hourly production level for each wind generation scenario in the study are shown in Table 4–2. These equations are graphically depicted in Figure 4–7.

Table 4–2 Approximate Equations for 10-minute variability

Scenario	Variability Approximation
20% Queue + Best Sites Onshore	$\sigma = [-4.67 \cdot 10^{-6}(HourlyWind^2) + 4.78 \cdot 10^{-2}(HourlyWind) + 1.91\,]\,MW$
20% Queue + Best Sites Offshore	$\sigma = [-7.44 \cdot 10^{-6}(HourlyWind^2) + 6.22 \cdot 10^{-2}(HourlyWind) + 1.20]\,MW$
20% Queue + Balanced Case	$\sigma = [-4.39 \cdot 10^{-6}(HourlyWind^2) + 3.54 \cdot 10^{-2}(HourlyWind) + 14.9\,]\,MW$
20% Queue + Best Sites by State	$\sigma = [-3.73 \cdot 10^{-6}(HourlyWind^2) + 3.80 \cdot 10^{-2}(HourlyWind) + 8.28\,]\,MW$
20% Queue + Best Sites Maritimes	$\sigma = [-3.05 \cdot 10^{-6}(HourlyWind^2) + 2.94 \cdot 10^{-2}(HourlyWind) + 10.3]\,MW$
14% Queue + Best Sites Onshore	$\sigma = [-6.61 \cdot 10^{-6}(HourlyWind^2) + 4.79 \cdot 10^{-2}(HourlyWind) + 3.85\,]\,MW$
14% Queue + Best Sites Offshore	$\sigma = [-7.33 \cdot 10^{-6}(HourlyWind^2) + 4.66 \cdot 10^{-2}(HourlyWind) + 7.54\,]\,MW$
14% Queue + Balanced Case	$\sigma = [-7.01 \cdot 10^{-6}(HourlyWind^2) + 4.34 \cdot 10^{-2}(HourlyWind) + 5.87\,]\,MW$
14% Queue + Best Sites by State	$\sigma = [-5.47 \cdot 10^{-6}(HourlyWind^2) + 3.99 \cdot 10^{-2}(HourlyWind) + 5.93\,]\,MW$
14% Queue + Best Sites Maritimes	$\sigma = [-5.27 \cdot 10^{-6}(HourlyWind^2) + 3.61 \cdot 10^{-2}(HourlyWind) + 4.41\,]\,MW$
9% Full Queue	$\sigma = [-1.14 \cdot 10^{-5}(HourlyWind^2) + 5.04 \cdot 10^{-2}(HourlyWind) + 1.80\,]\,MW$
2.5% Partial Queue	$\sigma = [-5.51 \cdot 10^{-5}(HourlyWind^2) + 6.60 \cdot 10^{-2}(HourlyWind) + 2.37\,]\,MW$

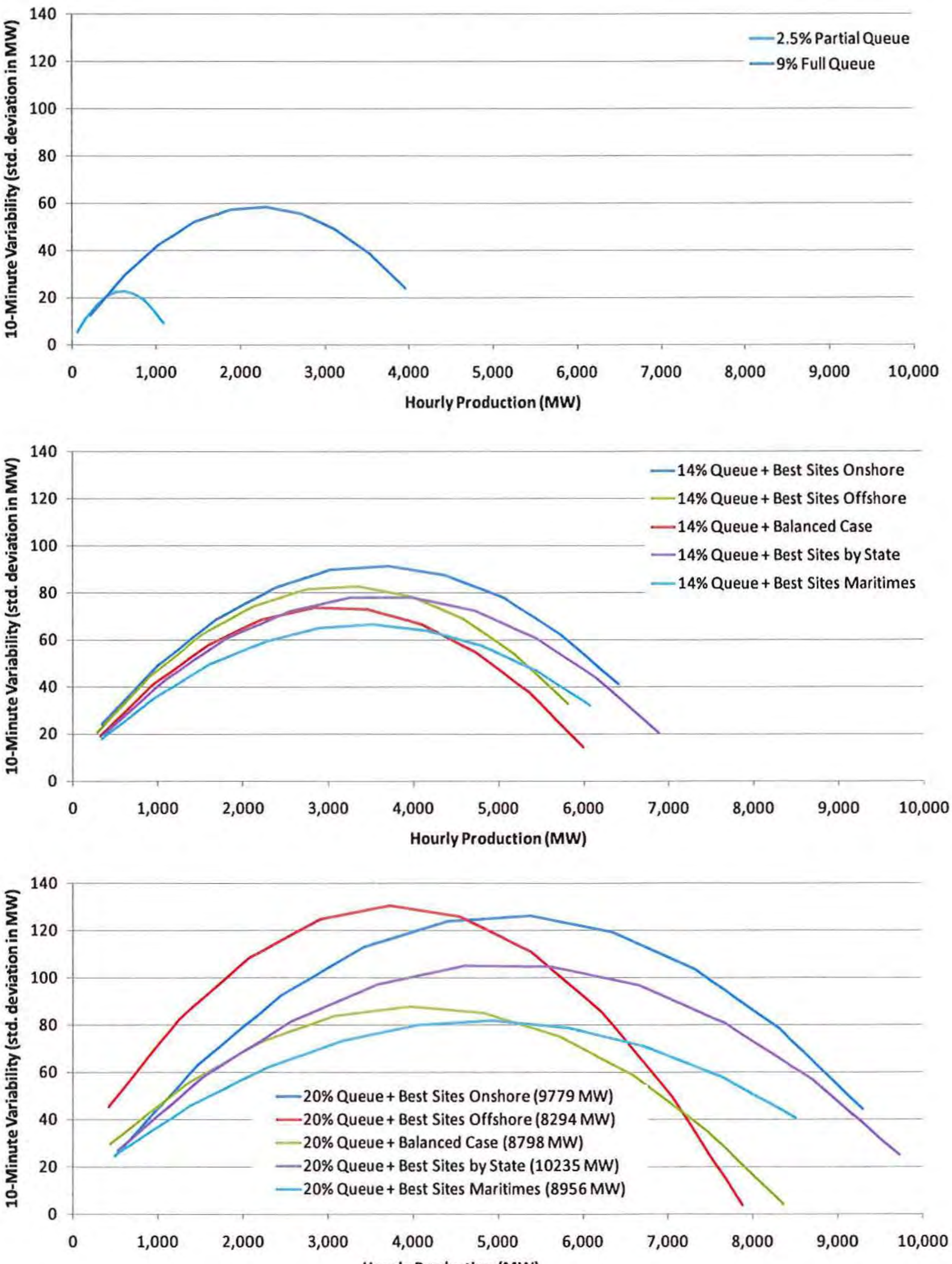


Figure 4–7 Quadratic approximations to empirical variability curves for study wind energy scenarios.

As mentioned previously, the variability of wind generation at this time scale is assumed to be uncorrelated with that of load, so a statistical combination of independent variables is appropriate. The calculation assumes that the total variability is the root mean square sum (RMS) of:

- The standard deviation of the load variability, assumed to be 1/3 of the regulation scheduled for the hour (encompasses 99.7% of all variations in the normal sample)
- The fast wind variability, taken as 2 MW per 100 MW of installed capacity. For each scenario, the total fast variability is the root-mean-square sum of the installed capacity divided by 100 times 2 MW squared. This component is included for completeness, but a very small contributor to the incremental regulation (per Equation 1).
- The longer-term wind variability or the difference between the short-term persistence forecast and the actual wind 10 minutes into the future. This error is taken as the variability from one 10-minute interval to the next and is a function of the expected hourly production level, i.e. the expected error is largest in the middle range of the aggregate production level per curves in Figure 4–7 above and the equations in Table 4–2.

Results of the calculations for all scenarios are shown in Table 4–3 through Table 4–5. The amount of additional regulation calculated for each hour depends on

- The amount of regulation carried for load alone. It should be noted that when more regulation is available, the incremental impact of wind generation is reduced due to the statistical independence of the variations in wind and load.
- The aggregate wind generation production level, since the statistics show that wind production varies more when production from 40 to 60% of maximum (Figure 4–7)

As can be seen in Tables 4-3 through 4-5, at 20% wind energy penetration, the average regulation requirement is estimated to increase from approximately 80 MW without wind, to a high of approximately 315 MW with 20% wind depending on the differences within the scenario. At lower penetration levels, the incremental regulation requirement is smaller. The hourly analysis indicates average regulation requirements would increase to a high of approximately 230 MW with 14% wind energy penetration. At 9% wind energy penetration, the average regulation would increase to approximately 160 MW. At the lowest wind penetration studied (2.5%); average required regulation capability would increase to approximately 100 MW.

The "Regulation – High Estimate" values apply a factor of 1.0 to the longer-term wind variability in the RMS calculation. A parallel analysis (described in 4.4.2) indicated that the results using this factor were likely conservative. Consequently, a "Regulation – Low Estimate" was computed by reducing the factor to 0.66. Because the regulation amounts vary based on the ISO-NE regulation schedule and the amount of hourly wind generation, the values reported are averages, maximums, and minimums. Distributions of hourly amounts for a full calendar year for a 20%, 14%, and 9% and 2.5% energy scenario are shown in Figure 4–8. Cumulative distributions for these scenarios are shown in Figure 4–9.

Table 4–3 Estimated Regulation Requirements for 20% Wind Scenarios

	Load	20% Queue + Best Sites Onshore	20% Queue + Best Sites Offshore	20% Queue + Balanced Case	20% Queue + Best Sites by State	20% Queue + Best Sites Maritimes
Regulation - High Estimate						
Maximum	200	433	442	335	380	321
Minimum	30	78	101	90	71	88
Average	82	290	313	234	249	221
Regulation - Low Estimate						
Maximum	200	328	333	272	297	264
Minimum	30	73	82	77	69	79
Average	82	211	224	175	186	167

Table 4–4 Estimated Regulation Requirements for 14% Wind Scenarios

	Load	14% Queue + Best Sites Onshore	14% Queue + Best Sites Offshore	14% Queue + Balanced Case	14% Queue + Best Sites by State	14% Queue + Best Sites Maritimes
Regulation - High Estimate						
Maximum	200	343	323	302	314	286
Minimum	30	76	62	64	62	75
Average	82	228	217	199	204	186
Regulation - Low Estimate						
Maximum	200	276	264	253	260	245
Minimum	30	68	59	60	60	68
Average	82	171	163	153	157	145

Table 4–5 Estimated Regulation Requirements for 9% and 2.5% Wind Scenarios

	Load	9% Full Queue	2.5% Partial Queue
Regulation - High Estimate			
Maximum	200	269	212
Minimum	30	50	37
Average	82	161	102
Regulation - Low Estimate			
Maximum	200	235	206
Minimum	30	50	37
Average	82	129	93

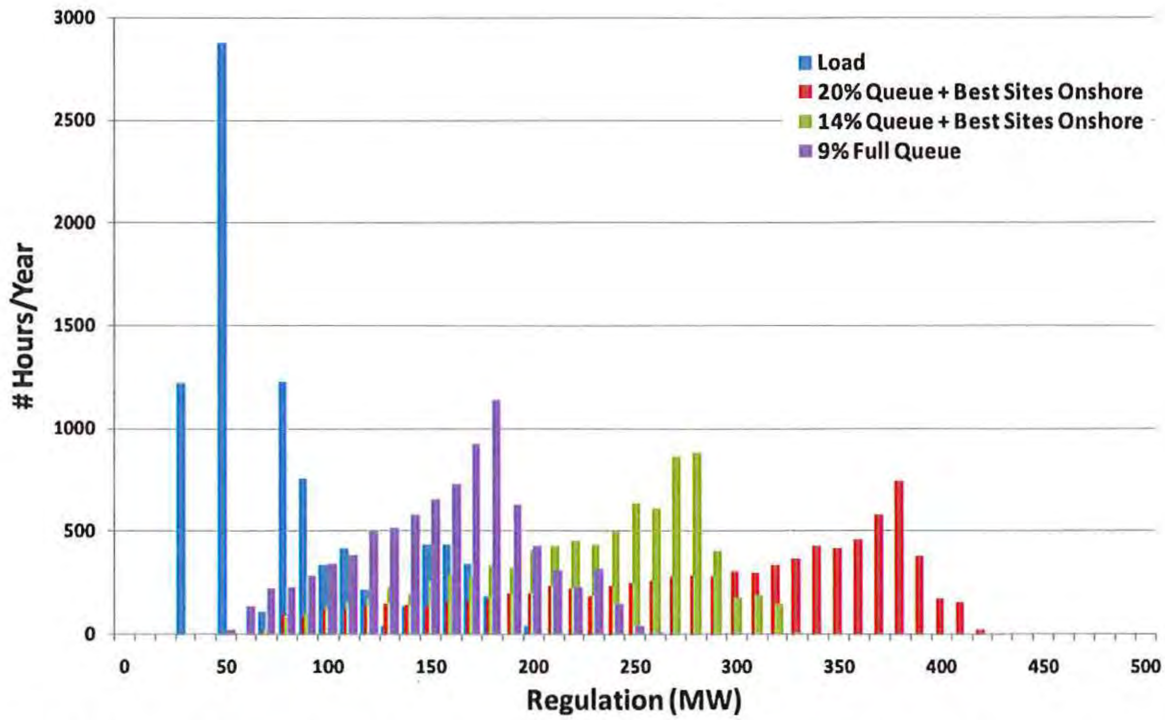


Figure 4–8 Distribution of hourly regulating requirements for ISO-NE load and selected wind generation scenarios

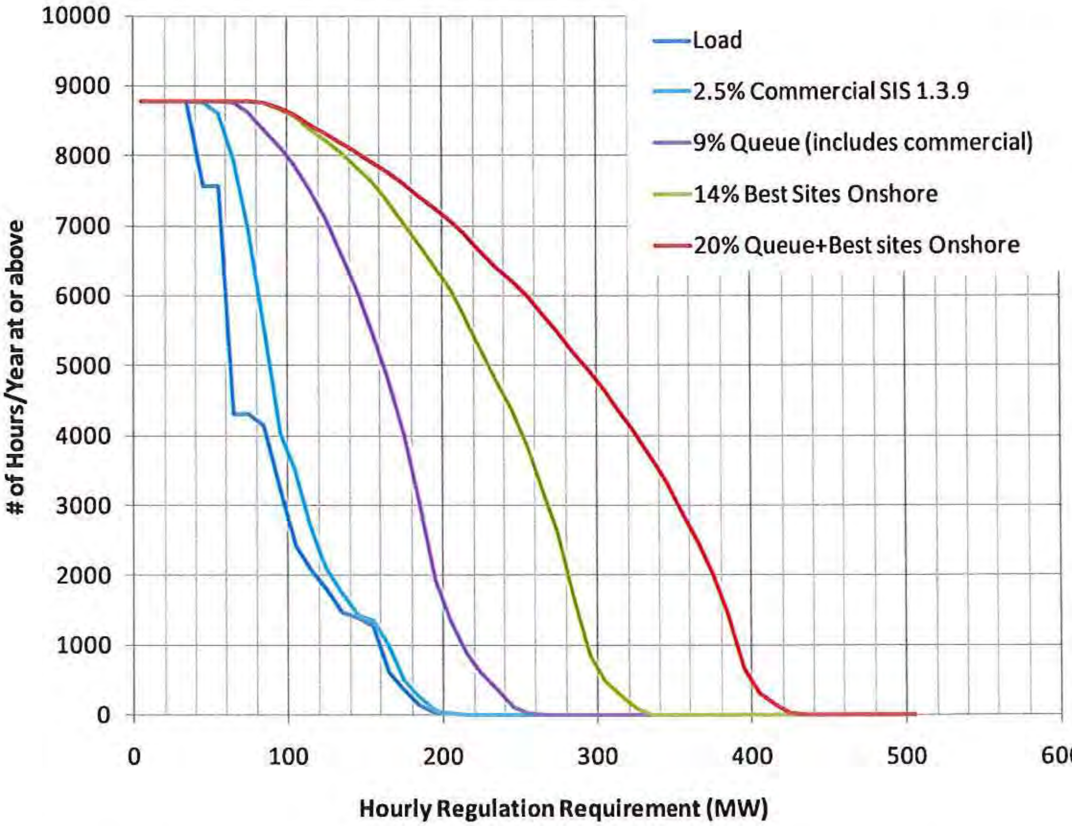


Figure 4–9 **Duration curve of estimated hourly regulation requirements ("Regulation: High Estimate") for load and selected wind scenarios**

Figure 4-9 shows regulation-duration curves for increasing levels of wind penetration. It shows the number of hours per year where regulation needs to be equal to or greater than a given value. For example, the dark blue curve (the left-most curve) shows that between 30 MW and 190 MW of regulation is required for load alone. The 2.5% Partial Queue scenario (the light blue line to the right of the load alone curve) increases the regulation requirement to between approximately 40 MW and 210 MW; the overall shape tracks that of the load alone regulation requirement curve. In the higher wind penetration scenarios, this minimum amount of required regulation capacity increases and the average amount of regulation required increases such that the shapes of the curves no longer track that of the load alone curve—this is indicative that the increased regulation capacity will likely be required to be utilized more frequently. The purple curve (the middle curve) shows that between approximately 50 MW and 270 MW of regulation is required with 9% wind energy penetration. The yellow and red curves (to the right of the 9% wind penetration curve just discussed) show that the required regulation increases to between approximately 75 MW and 345 MW and to between approximately 80 MW and 430 MW, respectively.

Based on the assumptions used in this analysis, the key factor in the additional regulation required for each scenario is the variability from one 10-minute interval to the next. The variability of each scenario on this time scale is a complicated function of the scenario definition and meteorology; predicting the variability of a given deployment of hundreds of wind turbines on this time scale is not possible. However, the high-resolution wind production data developed for this study allows the variability of a defined scenario to be characterized after the fact, facilitating this analysis.

The approach is likely not that different from that which will be used by ISO-NE as wind generation becomes more visible in power system operation. Archived measurements from the EMS could serve a role similar to that of the NEWRAM data.

4.4.2 Regulation Analysis Using Historical ACE Records

With guidance and assistance from ISO-NE operating personnel, additional analysis of regulation requirements was conducted with high-resolution (1-minute) load and synthesized wind data. The approach utilized ACE (area control error) values from the EMS archive for a calendar year. To this, the hourly scheduled regulation and the short-term wind generation persistence forecast were added as vectors.

For each 1-minute interval, a new ACE value was computed by adding the 10-minute wind generation forecast error to the ACE for load alone from the historical record. This augmented ACE value assumes that no regulation capacity is deployed to compensate for the difference between the actual wind generation and the amount that is scheduled into the sub-hourly energy market.

The average ACE for load and ACE net load are then calculated for each hour based on the sixty 1-minute samples. Each hour is then grouped according to some defined criteria – e.g. all weekday hours ending 0100, or all hours in the year where the scheduled regulation for load is X MW. In each grouping the ratio of regulation scheduled for load to the ACE for load is calculated. ACE for net load is then multiplied by that ratio to calculate the new regulation amount for net load in a particular grouping of hours.

The process used here first groups all hours by the amount of regulation being carried for load. Then, within each group, the data is sorted by the wind generation production level. Regulation-to-ACE ratios are calculated for each of these sub-groups. Results for the "20% Best Sites Onshore" scenario are shown in Figure 4–10. Values for the chart are found in Table 4–6 along with the average new regulation amounts for each level of scheduled regulation.

Table 4–6 Computed increases in Hourly Regulation Requirements from analysis of ACE

	Scheduled Regulation															
Wind Production Level	30	50	70	80	90	100	110	120	130	140	150	160	170	180	200	Average
0-999	1.21	1.31	1.10	1.19	1.23	1.11	1.11	1.10	1.16	1.04	1.08	1.04	1.04	1.10		113%
1000-1999	1.43	1.57	1.26	1.47	1.46	1.19	1.31	1.22	1.17	1.17	1.23	1.27	1.27	1.22	1.10	129%
2000-2999	1.78	1.79	1.33	1.55	1.67	1.38	1.32	1.33	1.47	1.30	1.40	1.47	1.31	1.31	1.40	145%
3000-3999	1.81	1.93	1.43	1.84	1.75	1.54	1.63	1.56	1.44	1.34	1.52	1.50	1.43	1.39	1.21	155%
4000-4999	2.29	2.03	1.31	1.82	2.21	1.41	1.52	1.49	1.56	1.20	1.48	1.65	1.33	1.48	1.25	160%
5000-5999	2.01	2.02	1.31	1.91	1.88	1.64	1.57	1.72	1.28	1.51	1.48	1.45	1.43	0.93	1.41	157%
6000-6999	1.73	2.04	1.50	2.02	1.73	1.53	1.70	1.52	1.29	1.31	1.28	1.37	1.44	1.50	1.12	154%
7000-7999	1.70	1.70	1.24	1.61	1.46	1.66	1.40	1.35	1.10	1.18	1.29	1.60	1.35	1.55		144%
8000-8999	1.30	1.37	1.16	1.25	1.38	1.23	1.10	1.01	1.16	1.70	1.11	1.13	1.14	1.07		122%
Average - % of Load Only	170%	175%	129%	163%	164%	141%	141%	137%	129%	130%	132%	139%	130%	128%	125%	
Average - MW	51	88	90	130	148	141	155	164	168	183	198	222	222	231	250	

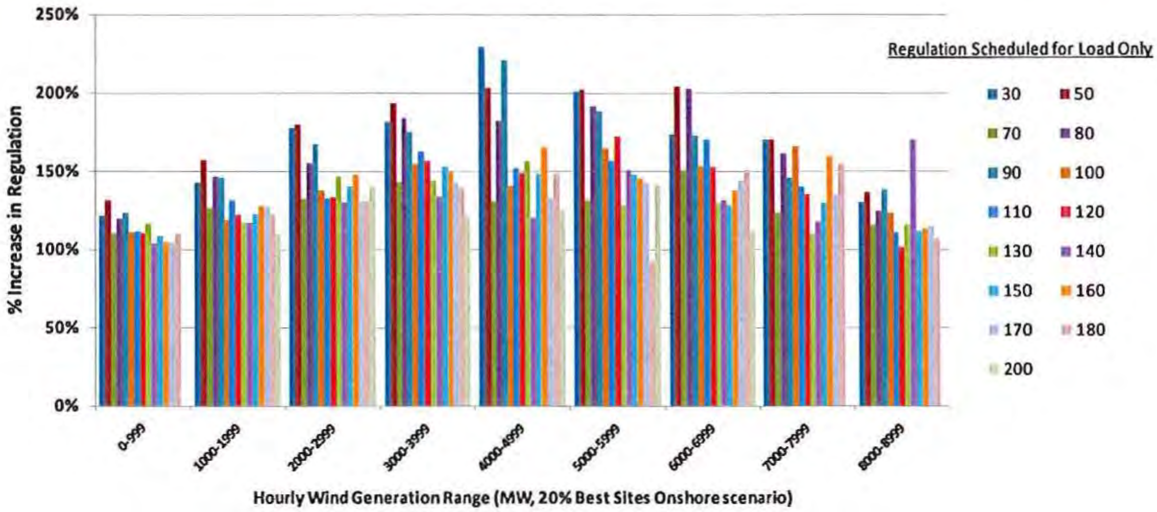


Figure 4–10 Hourly regulation requirements from ACE analysis methodology for "20% Queue + Best Sites Onshore" scenario; shown by hourly wind production level for each quantity of scheduled load regulation

Some points and observations regarding the analysis using ACE data:

- While an entire year of 1-minute data was used in the analysis, the sorting resulted in a few groupings with little or no data. For example, there were no hours with 200 MW of scheduled regulation and wind generation either 0-999 or 8000-8999 MW, so the empirical basis for these groupings could be questioned.
- The load hours were sorted by scheduled regulation only, so hours from different day-types and seasons were intermingled. This was done to increase the sample of hours in each of the defined groupings, but has the disadvantage of grouping hours with potentially different load compositions and characteristics.
- As can be seen from the column and row averages in Table 4–6, for the "20% Queue + Best Sites Onshore" scenario, the regulation amounts increase, on average, roughly 50% over the amounts currently scheduled for load. As expected the impact is higher when

wind generation is in the mid-range of aggregate nameplate production, with smaller impacts at both lower and higher levels.

The purpose of this analysis was to provide a check on the methodology using hourly data described in Section 4.4.1. A comparison of Table 4–6 with Table 4–3 through Table 4–5 suggests that the hourly methodology described earlier may be conservative. It should be recognized that both of the methods used here are approximate.

The fundamental assumption used in both approaches is that a portion of the wind generation variations within the hour will be addressed through dispatch in the sub-hourly energy market, and errors in the short-term wind generation forecast that go into the dispatch decisions will increase regulation requirements. A simple short-term persistence forecast was used here; in practice, more sophisticated algorithms will likely be embedded in ISO-NE automatic generation control. As the characteristics of the wind generation in actual operation are better learned through experience, the forecasting routines and other algorithms used to determine regulation needs will also improve. This will lead to an optimization over time of the amount of additional regulation scheduled and procured to deal with the increased net load variability due to wind generation.

For the remainder of this discussion, the most conservative of the previous calculations – namely the "Regulation – High Estimates" will be used.

4.4.3 Summary – Impacts of Wind Generation on ISO-NE Regulation Requirements

Based on the preceding analysis, summarized in Figure 4–9, the following conclusions regarding the impacts of wind generation on ISO-NE regulating requirements are made:

- For any of the wind generation scenarios examined, the amount of additional regulation needed to maintain control performance will vary with the current wind production level.
- The unique variability of each scenario is considered through the statistical characterization of the aggregate 10-minute data from the NEWRAM. A large number of factors influence this variability, and are beyond the scope of this analysis. However, sufficient empirical data provides a way to bypass such a complicated analysis, and instead utilize the observed or learned behavior of the aggregate wind generation for operational analysis.
- Fast fluctuations in wind generation – over tens of seconds to a minute – are relatively small due to smoothing effects and have very little impact on ISO-NE regulation requirements.

- The difference in variability between scenarios with the same energy penetration is reflected in these results. The differences in regulation impacts discernable amongst layouts at the same energy penetration levels can be traced directly to the statistics of variability used in these calculations. Based on the ISO-NE wind generation mesoscale data, some scenario layouts of wind generation exhibit higher variability from one ten-minute interval to the next than others. A number of factors could contribute, including the relative size of the individual plants in the scenario layout (and the impact on spatial and geographic diversity), the local characteristics of the wind resource as replicated in the numerical weather simulations from which the data is generated, and even the number of individual turbines comprising the scenario, as more turbines would imply more spatial diversity.
- Regulation requirement is only slightly increased at 2.5% penetration. The calculated change is likely within the "noise" of the assumptions and analytical methodology.
- At 9% penetration, the maximum hourly regulation requirement is changed by about 25%, and the average requirement over the year is about double (82 to 161 MW). With current practice for load alone, there are about 4000 hours in the years where the scheduled regulation is either 30 MW or 50 MW; at 9% wind penetration, the data shows less only 25 hours over the course of the year analyzed where the hourly regulation is 50 MW or less.
- At 14% penetration, average regulation requirements are more than doubled depending on scenario. With 20% energy penetration, average regulation could be nearly 4 times the amount currently carried by ISO-NE.
- The current practice for scheduling regulation may be impacted. Regulation quantities for specific hours and day types are determined months in advance in some cases, although the amount actually procured is determined nearer to real time. With wind generation, the amount scheduled in advance would have to be on the basis of the maximum possible wind generation variability. This would correspond most closely to the "Maximum" values shown in Table 4–3 through Table 4–5; the amount actually procured would depend on the actual wind generation level, and could be as low as the "Minimum" amounts in the same tables.
- Analysis by ISO-NE operations personnel and the analysis of historical ACE data provide evidence that even the "Low Estimate" regulation numbers shown in the tables may be conservative.

Regulation requirements at ISO-NE are continually evaluated and adjusted based on operating experience and a desire to maintain adequate control performance with economic efficiency. Consequently, regulation procured for any level of wind penetration will likely be highest initially, and then reduced over time as experience is gained. The analysis in this project was not intended to arrive at the "final numbers" that will be reached through the ISO-NE process, but rather to ascertain whether the probable increase in regulation requirements would be within the capability of the ISO-NE generating fleet.

After a review of the three estimates of increased regulation requirements, ISO-NE Staff concludes that there may be adequate supply and its business process is sufficiently robust to meet the challenges ahead.

4.5 Impacts on Other Operating Reserves

Regulation is just one piece of the ancillary services procured by ISO-NE to maintain system reliability. The impacts of wind generation as defined by the study scenarios on the other elements – 10-minute spinning reserve (TMSR), 10-minute Non-spinning Reserve (TMNSR), and 30-minute Operating Reserve (TMOR) – are examined here.

4.5.1 10-Minute Spinning Reserve (TMSR)

ISO-NE counts regulation resources toward their TMSR requirement. Conceivably, regulation could be near the top of the aggregate range when a contingency occurs, thereby actually reducing the amount of spinning reserve available for replacing lost generation. This current policy is based on years of experience. With additional regulation required by wind generation, the amount of TMSR available to respond to a contingency could be lower than the current minimum amounts.

Figure 4–11 shows the hourly profile of regulation for load, regulation for the "20% Queue + Best Sites Onshore" scenario (using the Regulation – High Estimate), and TMSR. It is apparent that the amount of TMSR available to deploy for contingencies is substantially reduced. In other words, the regulation for net load (in blue) can be as much as twice as large for load alone (in red) which decreases the capacity available for TMSR (the distance between black line and the blue or red lines, respectively). Figure 4–12 provides a closer view of four separate weeks from Figure 4–11.

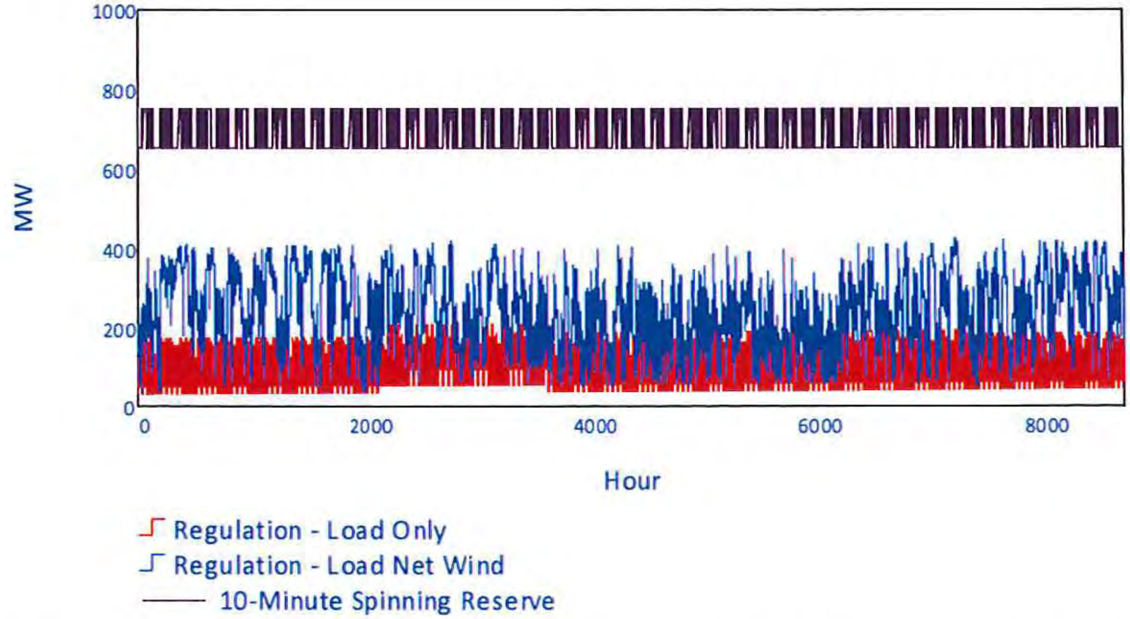


Figure 4–11 View of annual hourly regulation for load and net load for "20% Queue + Best Sites Onshore" scenario, shown with hourly TMSR

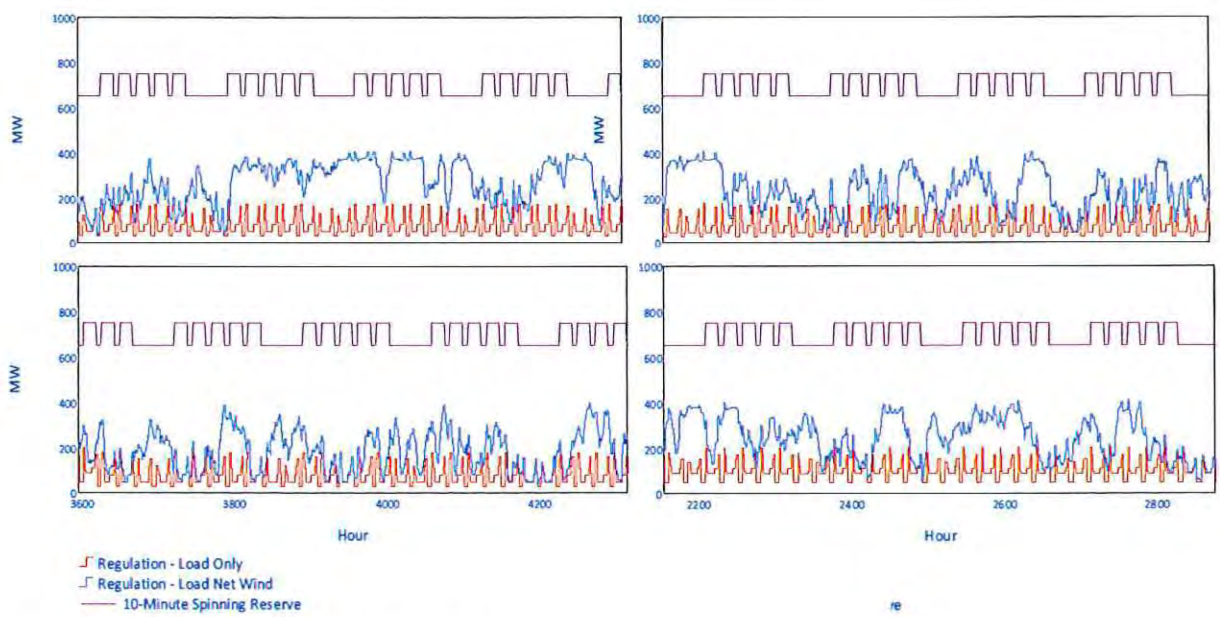


Figure 4–12 Expanded views of Figure 4–11

Figure 4–11 and Figure 4–12 show that the amount of available TMSR with load alone is never lower than 450 MW (650 TMSR – 200 MW Regulation). For this wind generation scenario, there are hours where the available TMSR is reduced to less than 250 MW. The minimum levels assume that the regulation is deployed in the upward direction to the maximum value, which would be a momentary condition until regulation is re-balanced, so this discussion focuses on a worst-case condition. Nonetheless, it could represent a vulnerability to a contingency event and would certainly merit close monitoring.

The current ISO-NE practice of counting regulation toward TMSR is based on experience. From this, it can be inferred that preserving the existing levels of available TMSR with wind generation would be consistent with current practice. To achieve this, TMSR would need to be supplemented by the incremental amount of average regulation required for wind generation. The amount of the supplement would be equal to the difference between the average regulation required for load and that required for wind generation.

Table 4–7 shows the additional TMSR required for each scenario should the policy described above be adopted. At penetrations exceeding 2.5%, TMSR would need to be increased to maintain current levels of contingency coverage with spinning reserve. These amounts range from 140 to 230 MW for the 20% scenarios, 100 to 150 MW for the 14% scenarios, and 80 MW for the 9% penetration level. Also, the table is based on the simplified modeling of operating reserves used in this study, so the actual procedure could be somewhat more complicated.

Table 4–7 Augmentation of TMSR for Incremental Wind Regulation

Scenario	Supplemental TMSR (MW)
20% Queue + Best Sites Onshore	208
20% Queue + Best Sites Offshore	231
20% Queue + Balanced Case	152
20% Queue + Best Sites by State	167
20% Queue + Best Sites Maritimes	139
14% Queue + Best Sites Onshore	146
14% Queue + Best Sites Offshore	135
14% Queue + Balanced Case	117
14% Queue + Best Sites by State	123
14% Queue + Best Sites Maritimes	104
9% Full Queue	79
2.5% Partial Queue	20

4.5.2 *Thirty Minute Operating Reserve (TMOR)*

The portions of ISO-NE operating reserves not performing regulation duty are held to cover major loss-of-supply contingencies, errors in forecasted load, loss of transmission elements, and to restore reserves upon the aforementioned events. Available spinning reserves respond immediately through inertial and governor action. To restore frequency, spinning reserves are dispatched upward and non-spinning reserves are started to both assist and replace spinning reserves. Over time, 30-minute reserves replace both types of 10-minute reserves that are now serving load along with the lost generation that created the contingency.

The regulation analysis above (Section 4.4) considers the real-time variability of wind generation and represents additional capacity needed to compensate for this variability, and shows how regulation capacity would need to increase for the wind generation scenarios considered in the study. The remaining questions are concerned with the impacts on other reserve categories.

Large changes in wind generation are of a markedly different nature than contingency events because:

- They do not occur instantaneously, but rather over longer periods of several tens of minutes to an hour or more;
- They are potentially predictable through advanced forecasting, which would provide operators with forewarning and time to adjust the operating plan in a somewhat economic manner.

The forecasting aspect is difficult to consider analytically since short-term forecasting, especially for significant wind events is relatively new and the performance that may be achievable is just speculative at this point in time. It therefore is not factored into the following analysis.

Using the "20% Best Sites Onshore" scenario as an example, changes in load and net load over periods ranging from one to four hours were analyzed. The distribution of hourly changes for over 26,000 hours in the three-year record is shown in Figure 4–13. Figure 4–14 provides and expanded view of the right-hand portion of the distribution, where the net change is in the positive (increasing net load) direction.

The working assumption is that the ISO-NE system is capable of responding to the largest hourly increases in load, but beyond that, operating reserves would be needed to meet the net load increase. The significance of the figures is that there are only 28 events where the hourly increase in load net of wind generation exceeds 3300 MW, which is the highest load-only change over the 26,000 hours of data. Since the 20% Best Sites Onshore is one of the most variable (Figure 4–7, highest standard deviation of 10-minute changes), it appears that the 30-minute operating reserve for load alone would be adequate to cover any changes in net load, assuming that it could be deployed on average about 10 times per year. In discussions during project meetings, it was recognized that maintaining enough additional reserve such that current levels of TMOR would never be deployed for large changes in wind was likely uneconomic. At the same time, TMOR is intended for contingency events, which at this time do not include large declines in wind generation over periods of 30 minutes to an hour or more. Based on current operating practice, it was thought that invoking TMOR once per month or less for wind generation reductions was a reasonable middle ground for purposes of this study.

TMOR would only be used if there were no other resources available to compensate for the reduction in wind generation.

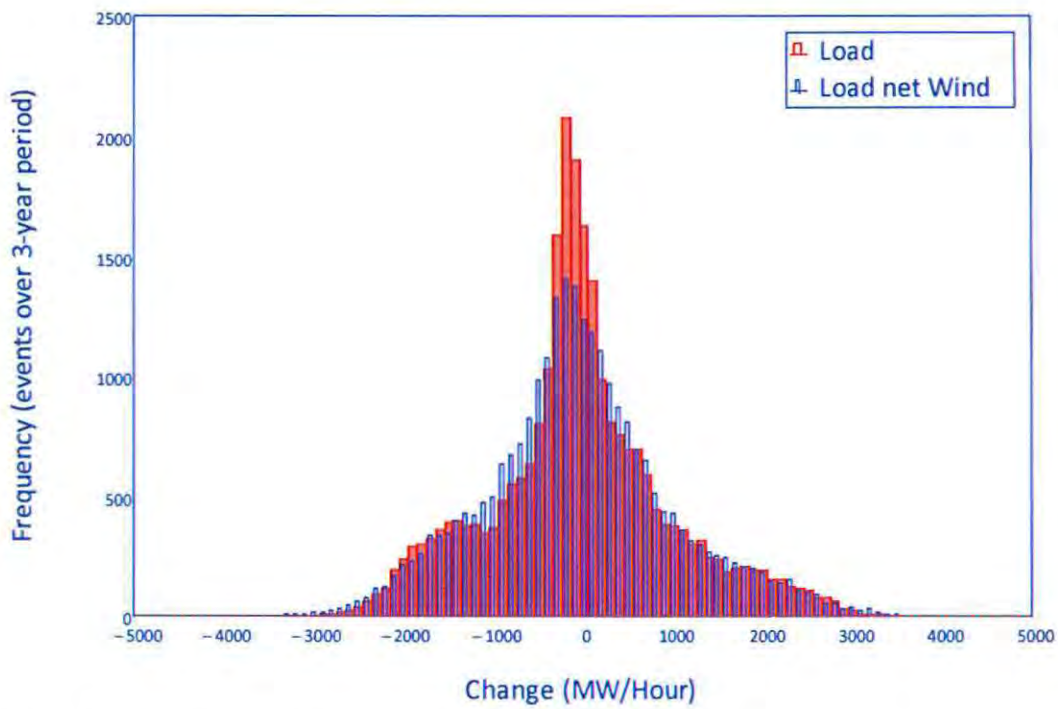


Figure 4–13 Hour changes in load and net load for 20% Best Sites Onshore scenario

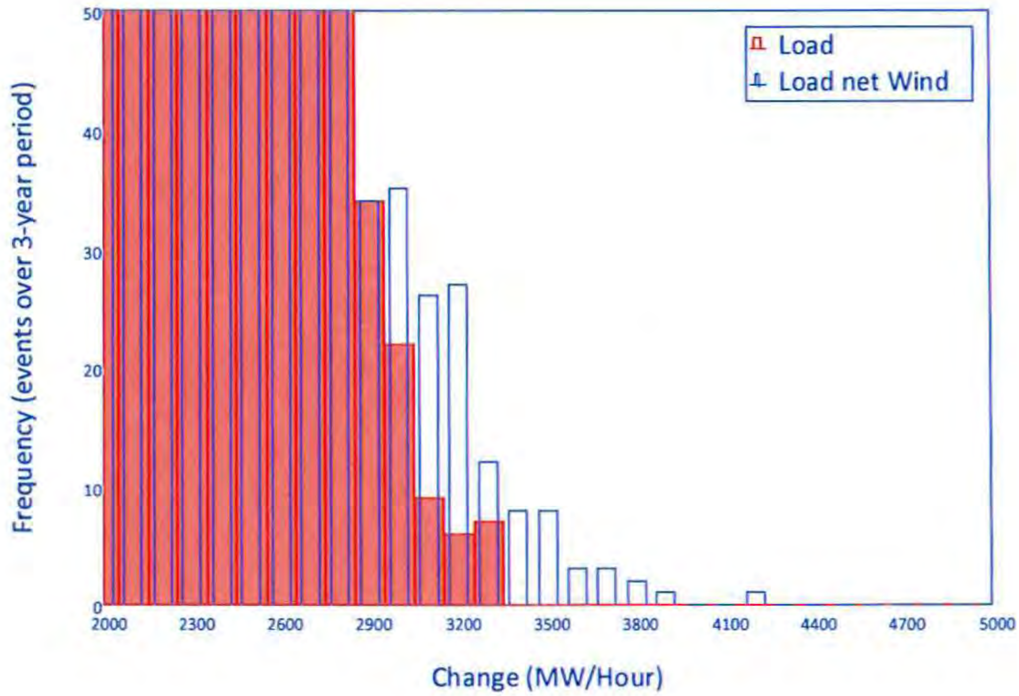


Figure 4–14 Expanded view of Figure 4–13

4.5.3 Ten-Minute Non-Spinning Reserve (TMNSR)

Changes in wind generation over an hour are used as an initial metric for assessing impacts on TMNSR. Figure 4–15 shows the standard deviation of the hourly changes as a function of production level for the wind scenario used in this example. The data can also be interpreted as the expected error in a 1-hour persistence forecast.

Short-term forecast errors, in this case the projection of wind energy delivered in the next hour, must be addressed with some type of conventional capacity. The types of capacity available in the hour include:

- Regulation
- Capacity participating in the sub-hourly energy market
- TMSR
- TMNSR
- Some TMOR

As described above, TMSR resources (as augmented for wind generation in consideration of the additional regulation capacity needed for real-time variability) would not be used to make up for under-delivery of wind energy. Regulation capacity could be used initially, but must be replaced by other resources to maintain headroom. Resources in the sub-hourly energy market would have some capability to be dispatched up to make up for a portion of the lower-than-forecast wind generation, but may be inadequate to replace it all.

For very large hourly changes (hourly persistence forecast errors) resulting in under-delivery of wind energy, non-spinning reserves may need to be deployed to either off-load regulating resources or supplement capacity in the sub-hourly market. Closer inspection of the data behind Figure 4–16 reveals that wind generation in the 20% Best Sites Onshore scenario could be expected to drop more than 1500 MW over an hour about 0.3% of the hours, or about 25 times per year. For very large hourly changes (hourly persistence forecast errors) resulting in under-delivery of wind energy, non-spinning reserves may need to be deployed to either rebalance regulating resources or supplement capacity in the sub-hourly market. Expected 1-hour persistence forecast errors for the 20% Best Sites Onshore scenario are shown in Figure 4–16.

The standard deviations of the expected hourly changes for this scenario are shown in Figure 4–15. Figure 4–16 shows the range of hourly changes for the 20% Best Sites Onshore scenario as a function of current hourly production. The diamond symbols are the standard deviation of the expected hourly change, and the ends of the vertical lines represent the largest single hourly changes observed in the three years of data. The maximum drop is 2100 MW (occurring when hourly production is between 60% and 70% of aggregate nameplate capacity) in the three years of data available for analysis. As assumed for this study, TMNSR is either 650 or 750 MW depending on the hour. Inspection of the hourly load changes shows that, for all hours, the standard deviation of the expected change is about 1000 MW, with a maximum load increase of 3300 MW occurring on 7 occasions over the three-year hourly load sample. However, if wind generation were to decrease by a large amount during a period where load was anticipated to be flat and there was a minimum amount of flexible, dispatchable capacity available, the ability of the sub-hourly market resources to make up for the deficit could be limited. In such a period, TMNSR would need to be deployed but could compensate for only part of the deficit by current practice.

The varying volatility of wind generation with production level and the low correlation to load cycles makes direct augmentation of TMNSR difficult. A different mechanism for securing additional 10-minute non-spinning reserves which recognizes the probability of a large reduction in wind generation and the ability of market resources to compensate may be a better solution (e.g. new ERCOT 15-minute market product). Since the reductions in wind generation under consideration here happen over an hour or substantial fraction thereof and may be predictable, it is also not clear that the 10-minute capability would be necessary; some combination of 10-minute and 30-minute reserves could provide the range required over time to meet the decline in wind energy delivery.

In addition, there would almost always be some flexibility to be drawn from sub-hourly energy market resources. The large changes in wind generation under consideration here happen over an hour, or several consecutive sub-hourly market clearing intervals. Even a simple persistence forecast would capture a portion of this large wind ramp, albeit with some time lag, and feed it into the calculation of the sub-hourly market clearing, thereby extracting upward movement from energy market resources.

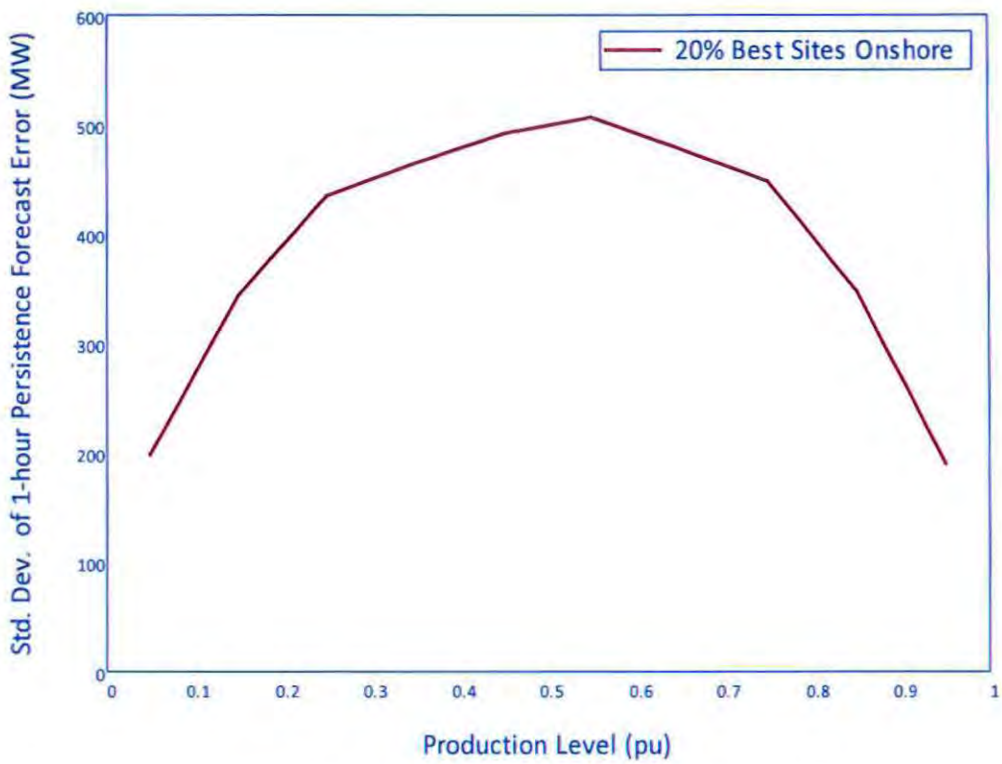


Figure 4–15 1-hour persistence forecast error for 20% Best Sites Onshore scenario

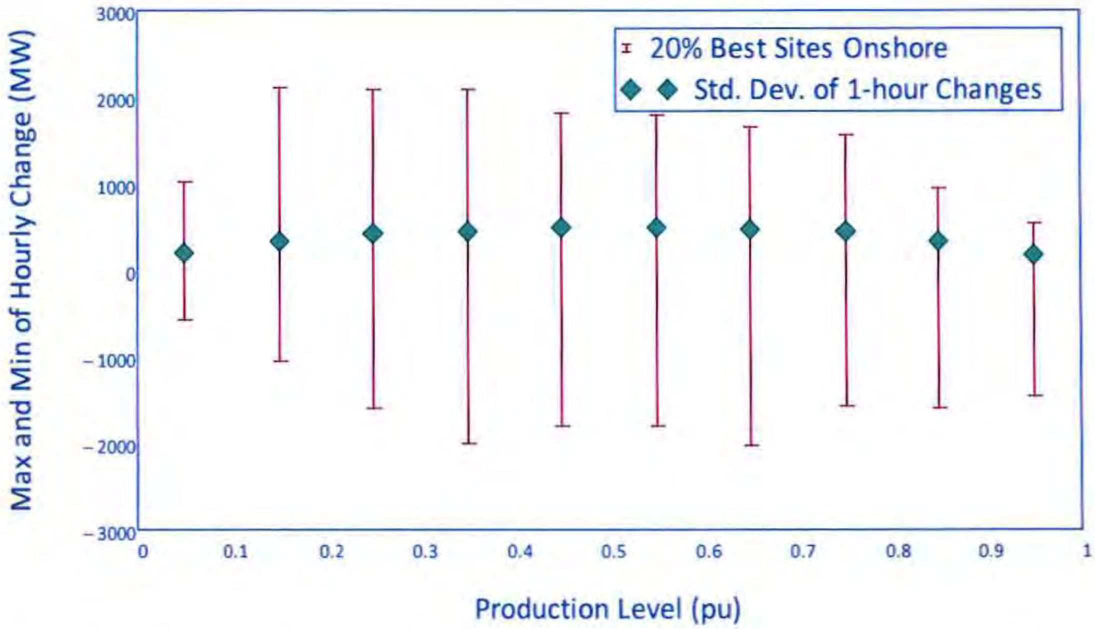


Figure 4–16 Maximum and minimum hourly wind generation changes from three-years of "20% Queue + Best Sites Onshore" scenario data

The GE MAPS production simulations provide guidance regarding the within-hour flexibility, as it tracks a range of information about generation in each hour of simulation. In addition, the production simulations have directly "seen" the hour-to-hour changes in net load, and deployed generation to meet those changes within the range and ramp limits of each individual unit.

A thorough examination of MAPS results for the 20% Best Sites Onshore case for 2006 load and wind patterns was conducted. State-of-the-art day-ahead wind generation forecasting was utilized in the unit commitment for this case. The objectives were to use the simulations to confirm some of the statistical analysis presented here, as well as to shed additional light on the in-hour flexibility that resulted from commitment and dispatch of the ISO-NE fleet.

The summarized hourly production simulation results in MAPS quantified the commitment status and dispatch of all units by technology and fuel type, and also reported the status of the aggregate constraints. Included here for each generator type were:

- Maximum and minimum generation – defines the highest and lowest possible dispatch levels for the generation online each hour. Maximum generation is taken as the total committed generation for the hour; minimum aggregate generation level is reported directly by MAPS from operating data on individual committed units.

- Range-up - the difference between the hourly dispatch point and the maximum possible dispatch, for each hour
- Range-down, as above, for each hour
- Ramp rates, both down and up, reported in MW/min, at the start of each hour

Chronological ISO-NE load and scenario wind data at 10-minute resolution was examined to determine the maximum range up and down from the average hourly value for net load. The maximum ramp rates, up and down, were also computed as the largest change net load from one ten-minute interval to the next within each hour.

The highest range and ramp values for each hour computed from the 10-minute data were then compared to the production simulation results. The hourly flexibility in terms of range was first adjusted by subtracting out the specified TMSR for the hour (either 650 MW or 750 MW per the assumptions used in the study), as this generation is necessary to provide regulation and cover contingency events. The number of hours where the maximum range of net load, up or down, exceeded the hourly range flexibility was counted. A similar process was used for ramp rate, although the ramp rates reported by MAPS were used without adjustment for units that would be on regulation duty. Results for the 20% Best Sites Onshore case are shown in Table 4–8.

Table 4–8 Results from analysis of MAPS data for 20% Best Sites Onshore scenario

	# of Hours where requirement exceeded capability			
Case	Range UP	Range Down	Ramp UP	Ramp DN
20% Best Sites Onshore	191	55	3	205

The table shows that in 191 out of 8784 hours in the production simulation, the available range up (adjusted to remove the TMSR) was not adequate to cover the highest deviation of 10-minute load-net-wind generation from the hourly average. There are two implications of this deficiency:

- Spinning reserves held for regulation and contingency would be dispatched, thereby reducing the available TMSR; demand response with sufficient response capability could count toward this requirement
- Quick-start units would be deployed to provide additional flexibility and replace TMSR that was being dispatched, possibly reducing TMNSR below criteria.

The Range Down violations could be addressed by wind generation curtailment, as discussed in the Task 2 report for this study. Ramp Down violations result from either a large decrease in load or sudden increase in wind generation. For wind, ramp-rate control would be a possible solution (Task 2 report). There were only 3 violations of the Ramp UP capability, which is likely within the "noise" of the assumptions and process used here.

To better calibrate the analysis, the same procedure was applied to a "No Wind" case. It was found that the flexibility limitations were exceeded in some hours here as well. The effect of wind generation is then taken to be the difference between the cases with and without wind generation. These results are shown in Table 4–9.

The existence of apparent violations in the "No Wind" case is a reflection of "extending" the resolution of the hourly chronological production simulations to view intra-hour phenomena. The production simulations enforce unit constraints on an hourly basis; in effect, it is assumed that the load or net load is moving smoothly from one hourly value to the next. The preceding analysis fills in detail by comparing hourly values – Range Up, Range Down, etc. – to higher resolution data at ten-minute time steps. Consequently, the analysis is far from exact; the results of this analysis, however, are still considered useful and revealing, in that the flexibility of the system each hour is compared to requirements ascertained from closer examination of changes within each hour.

Table 4–9 Comparison of MAPS analysis results for 20% Best Sites Onshore and No Wind cases

	# of Hours where requirement exceeded capability			
Case	Range UP	Range Down	Ramp UP	Ramp DN
20% Best Sites Onshore	191	55	3	205
No Wind	100	39	3	193
Difference	91	16	0	13

The differences between the cases show very little impact of wind generation on flexibility except for the Range UP criteria. Additional generation would need to be quickly deployed about 7 or 8 times per month (91/12) to replenish TMSR and rebalance the reserves. This assumes that the quick-start capacity to cover wind declines or load increases would be drawn from the TMNSR.

The question of whether TMNSR should be augmented comes down to the criteria for using it. Figure 4–17 provides a view of the frequency and magnitude of the "Range Up" deficiencies for the 20% Best Sites Onshore and No Wind cases. Using the No Wind case as a baseline, it is first assumed – somewhat arbitrarily, but drawn from discussions during Technical Review

Committee meetings with ISO-NE staff - that for purposes of this evaluation assume that TMNSR can be called on up to 10 times in a year to compensate for large load increases or wind generation decreases. So, to limit TMNSR deployment to this number for the case with wind, the chart indicates that an additional 300 MW of non-spinning reserve, beyond that defined as TMNSR, would need to be available (300 MW is the approximate difference along the horizontal axis between the No Wind case and the With Wind case at 10 events/year).

This is only a rough approximation, since the results of this analysis show that for load alone, there are 100 hours in the annual simulation where the available range up flexibility was insufficient. The "allowable events/year" actually comes from current ISO-NE practice, where TMNSR is occasionally deployed for large increases in load. However, there is some disconnect between the production simulations here and reality, as 100 times per year is far higher than experience shows. That is why the difference between the cases is used as the metric.

It should also be noted that this additional quick-start generation would be needed only when indicated by wind generation conditions – if wind generation production were very low or predicted to be very low, there would obviously be no concern. And, the production simulations show no hours where the available quick-start generation (beyond the amount designated as TMNSR) would be less than the capacity required to supplement the aggregate range up sufficiently to cover the load-net-wind generation change.

Because sufficient quick-start generation appears to be available at all hours, there would always be adequate capacity to meet the TMNSR requirement as well as supplementing flexibility to meet large short-term changes in wind generation. The question actually appears to be one of semantics, but in reality it likely comes down to the market mechanisms required to ensure both adequate TMNSR as presently defined and additional non-spinning reserve to cover very large wind reductions when conditions warrant (i.e. there would be no need to designate additional TMNSR if wind production levels are low or within the capability of the sub-hourly market resources).

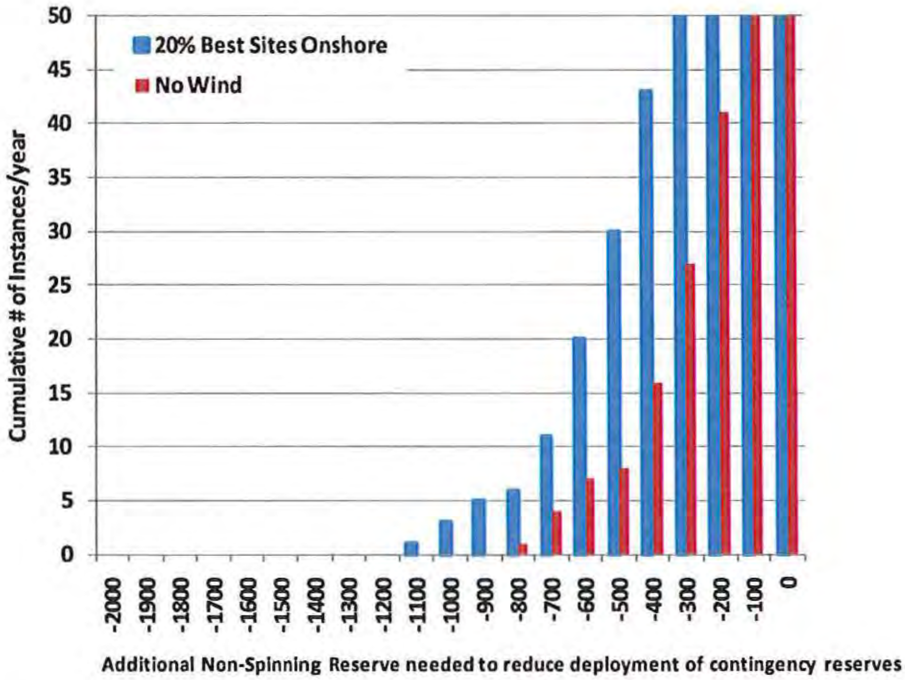


Figure 4–17 Additional non-spinning reserved needed for large wind changes to maintain TMSR at criteria for contingencies – 20% Best Sites Onshore case

A similar analysis was conducted for the 9% penetration case. Results are shown in Table 4–10. The number of times that Range Up capability within the hour was insufficient is lower than observed in the 20% case.

The "Range Up" violations are of primary interest for comparison to the 20% case analyzed previously. The reduction in the number of "Ramp Dn" violations is curious, however. Time limitations prevented a detailed examination; however, as explained earlier, these would be associated with large increases in wind generation. If real, rather than an artifact of the approximate nature of this analysis combined with coincidence, the issue would not be one of ISO-NE fleet limitations and is addressable by the ramp rate (up) limits as described in the Task 2 report.

Table 4–10 Comparison of MAPS analysis results for 9% Energy Queue and No Wind cases

	# of Hours where requirement exceeded capability			
Case	Range UP	Range Down	Ramp UP	Ramp DN
9% Energy Queue	136	0	3	8
No Wind	100	39	3	193
Difference	36	-	0	-

As expected, the additional non-spinning reserve needed to reduce the events/year (beyond the No Wind case) to 10 is smaller than for the 20% case. From Figure 4–18, the difference between the wind and no wind cases at 10 events per year is about 100 to 150 MW.

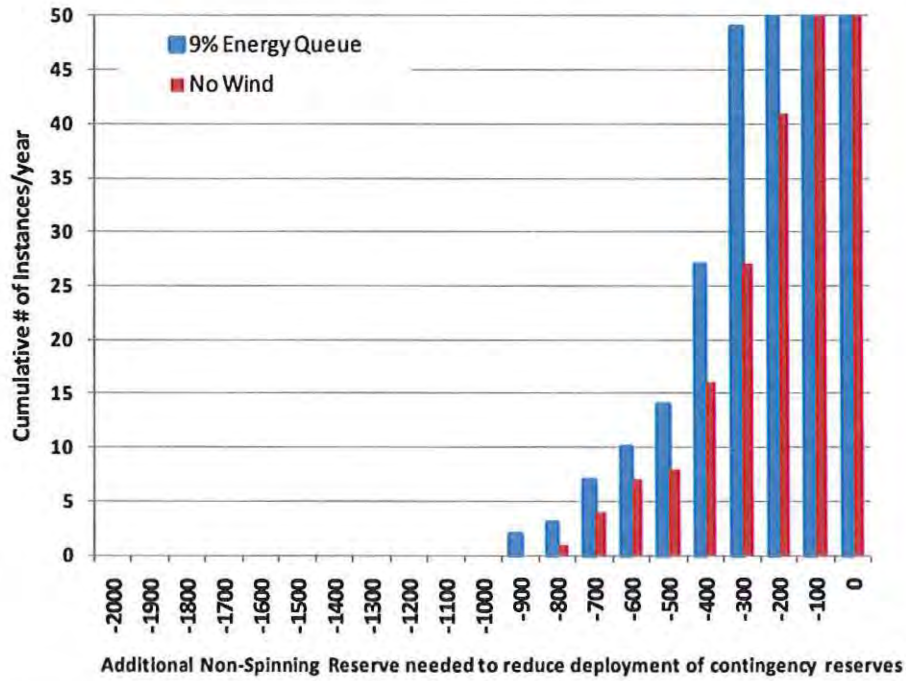


Figure 4–18 Additional non-spinning reserved needed for large wind changes to maintain TMSR at criteria for contingencies – 9% Energy Queue case

Two data points for operating reserve impacts of wind generation have been developed through approximate, but detailed, examination of the MAPS production simulation results. Taking into account the intra-hour flexibility of the ISO-NE fleet reported from the chronological hourly production simulation results, some additional operating reserve, primarily in the form of 10-minute non-spinning reserve is indicated for the 20% scenario analyzed. A smaller amount is needed at the 9% penetration level.

It should also be noted that the available quick-start capacity in the cases above far exceeded in every hour what would have necessary to remedy the reported violations. Availability in the production simulations indicates only that the fleet possesses the required capacity resources; some mechanism would need to be established to ensure access.

Due to the approximate nature of this analysis, results for other penetration levels and variants of the penetration levels analyzed here are drawn from an extrapolation of these results. Detailed analysis of alternate scenarios at 20%, for example, may produce slightly different numbers than the case described here. However, it would be difficult to discern whether the differences are actually a result of the scenario characteristics or fall within the "noise" of the approximate calculation.

Table 4–11 shows the results of this analysis as applied to all scenarios. The additional TMNSR, which as described above might be implemented as a new market product, would only be procured when indicated by wind generation conditions. Given the likely lead times, they would be based on forecast of wind generation, either a day or some hours ahead. In addition, the need for additional TMNSR would also be a function of system conditions, namely the amount of intra-hour maneuverability in the sub-hourly market.

And, as mentioned above but worth mentioning again, the production results show this additional quick start capability to be available all hours of the year.

Table 4–11 Additional TMNSR from Detailed Analysis of Production Simulations and 10-minute Data

Energy Penetration Level	*Additional TMNSR
20% - All scenarios	300 MW
14% - All scenarios	**225 MW
9%	150 MW
2.5%	**0 MW

* carried only during hours of high wind production

**extrapolated

4.6 Observations and Conclusions

Conclusions regarding wind generation impacts on ISO-NE operating reserves along with other observations and recommendations are described here.

4.6.1 Regulation

Significant penetration of wind generation will increase the regulation capacity requirement and will increase the frequency of utilization of these resources. The study identified a need for an increase in the regulation requirement even in the lowest wind penetration scenario (2.5% wind energy), and the requirement would have noticeable increases for higher penetration levels. For example, the average regulation requirement for the load only (i.e., no wind) case was 82 MW. This requirement increases to 161 MW in the 9% wind energy scenario—and to as high as 313 MW in the 20% scenario.

The primary driver for increased regulation requirements due to wind power is the error in short-term wind power forecasting. The economic dispatch process is not equipped to adjust fast enough for the errors inherent in short-term wind forecasting and this error must be balanced by regulating resources. (This error must be accounted for in addition to the load forecasting error.)

There are some differences in regulation impacts discernable amongst scenarios at the same energy penetration levels. This can be traced directly to the statistics of variability used in these calculations. Based on the ISO-NE wind generation mesoscale data, some scenarios of wind generation exhibit higher variability from one ten-minute interval to the next than others. A number of factors could contribute, including the relative size of the individual plants in the scenario (and the impact on spatial and geographic diversity), the local characteristics of the wind resource as replicated in the numerical weather simulations from which the data is generated, and even the number of individual turbines and wind plants comprising the scenario, as more turbines and more wind plants would imply more spatial diversity.

At the same time, however, the differences may be within the margin of uncertainty inherent in the analytical methodologies for calculating regulation impacts. Given these uncertainties, it is difficult to draw concrete conclusions regarding the relative merits of one scenario over the others from the regulation viewpoint. For example, future developments in short-term wind generation forecasting could result in a more variable, but easier to forecast, deployment of wind generation a smaller burden on regulation, since a large proportion of the changes would be scheduled into the sub-hourly energy market.

ISO-NE routinely analyzes regulation requirements and makes adjustments. As wind generation is developed in the market footprint, similar analysis will take control performance objectives and the characteristics of the operating wind generation through empirical data into account. At a minimum, high-resolution data for all wind generation facilities should be collected and archived. When regulation needs are analyzed, approaches like those illustrated in this report or others developed by ISO-NE staff can be used to augment the current methods for evaluation regulation requirements.

Analysis of these results indicates, assuming no attrition of resources capable of providing regulation capacity, that there may be adequate supply to match the increased regulation requirements under the wind integration scenarios considered. ISO-NE's business process is robust and is designed to assure regulation adequacy as the required amount of regulation develops over time and the needs of the system change.

4.6.2 Other Operating Reserves

Additional operating reserves will likely be required as wind penetration grows. The analysis indicates that TMSR would need to be supplemented as penetration grows to maintain current levels of contingency response. Increasing TMSR by the average amount of additional regulation required for wind generation would insure that the spinning reserve are available for contingencies would be consistent with current practice.

Using this approach, TMSR would be increased by 300 MW or so for the 20% scenarios, up to 150 MW for 14% energy penetration, and about 80 MW for 9% penetration.

The amount of additional non-spinning reserve that would be needed under conditions of limited market flexibility and volatile wind generation conditions is about 300 MW for the 20% Best Sites Onshore case, and 150 MW for the 9% Energy Queue case. This incremental amount would maintain the TMNSR designated for contingency events per existing practice, where it is occasionally deployed for load changes or large forecast errors. "Volatile wind generation conditions" would ultimately be based on ongoing monitoring and characterization of the operating wind generation. Over time, curves like those in Figure 4–7 would be developed from monitoring data and provide operators with an increasingly confident estimate of the expected amount of wind generation that could be lost over a defined interval.

In additional to the penetration level, the amount is also dependent on the following factors:

- The amount of upward movement that can be extracted from the sub-hourly energy market – the analysis indicates that additional TMNSR, or a separate market product for wind generation, would be needed on average only about 7 or 8 times per month at 20% penetration.
- The current production level of wind generation relative to the aggregate nameplate capacity.
- The number of times per period (e.g. year) that TMSR and TMOR can be deployed – for the examples here, 10 was assumed.

The additional TMNSR would be used to cover anticipated extreme changes (reductions) in wind generation. As such, it purpose and frequency of deployment are different that the current TMNSR. A separate market product that recognizes these differences may be advisable.

At 20% energy penetration, extreme changes in load net wind generation over several tens of minutes to an hour or more are only slightly larger than those seen for load alone. The data shows only 28 events over three years of hourly data where the increase in load net wind generation is greater than the maximum increase in load alone. The magnitude of these events is within the capability of the total operating reserves carried by ISO-NE according to current practice. The large hourly changes have also been evaluated directly in the production simulations, and therefore have been considered in the detailed analysis described in 4.5.3.

Due to the increases in TMSR and TMNSR, overall Total Operating Reserve (TOR) increases in all wind energy scenarios. For the 2.5% wind energy scenario, the average required TOR increases from 2,250 MW to 2,270 MW as compared to the no wind energy scenario baseline. The average required TOR increases to approximately 2,600 MW with 14% wind penetration and about 2,750 MW with 20% penetration.

The need for additional reserves varies as a function of wind generation. Therefore, it would be advantageous to have a process for scheduling reserves day-ahead or several hours ahead, based on forecasted hourly wind generation. It may be inefficient to schedule additional reserves using the existing "schedule" approach, by hour of day and season of year, since that may result in carrying excessive reserves for most hours of the year. The process for developing and implementing a day-ahead reserves scheduling process may involve considerable effort and investigation of this process was outside the scope of the NEWIS.

A summary of the estimated operating reserve impacts by scenario is found in Table 4–12.

Table 4–12 Summary of Operating Reserve Impacts for Study Wind Generation Scenarios

Scenario	Regulation (MW)	TMSR (MW)	TMNSR (MW)	TMOR (MW)	Ave. TOR (MW)
Load Only	82	750	750	750	2250
20% Queue + Best Sites Onshore	290	958	1050	750	2758
20% Queue + Best Sites Offshore	313	981	1050	750	2781
20% Queue + Balanced Case	234	902	1050	750	2702
20% Queue + Best Sites by State	249	917	1050	750	2717
20% Queue + Best Sites Maritimes	221	889	1050	750	2689
14% Queue + Best Sites Onshore	228	896	975	750	2621
14% Queue + Best Sites Offshore	217	885	975	750	2610
14% Queue + Balanced Case	199	867	975	750	2592
14% Queue + Best Sites by State	204	873	975	750	2598
14% Queue + Best Sites Maritimes	186	854	975	750	2579
9% Full Queue	161	829	900	750	2479
2.5% Partial Queue	102	770	750	750	2270